Competing uses of biomass: Assessment and comparison of the performance of bio-based heat, power, fuels and materials

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ABSTRACT

The increasing production of modern bioenergy carriers and biomaterials intensifies the competition for different applications of biomass. To be able to optimize and develop biomass utilization in a sustainable way, this paper first reviews the status and prospects of biomass value chains for heat, power, fuels and materials, next assesses their current and long-term levelized production costs and avoided emissions, and then compares their greenhouse gas abatement costs. At present, the economically and environmentally preferred options are wood chip and pellet combustion in district heating systems and large-scale cofiring power plants (75–81 US\$$_{2005}$/tCO$_2$-eq$_{avoided}$), and large-scale fermentation of low-cost Brazilian sugarcane to ethanol (-65 to -53 \$/tCO$_2$-eq$_{avoided}$) or biomaterials (-60 to -50 \$/tCO$_2$-eq$_{avoided}$ for ethylene and -320 to -228 \$/tCO$_2$-eq$_{avoided}$ for PLA; negative costs represent cost-effective options). In the longer term, the cultivation and use of lignocellulosic energy crops can play an important role in reducing the costs and improving the emission balance of biomass value chains. Key conversion technologies for lignocellulosic biomass are large-scale gasification (bioenergy and biomaterials) and fermentation (biofuels and biomaterials). However, both routes require improvement of their technological and economic performance. Further improvements can be attained by biorefineries that integrate different conversion technologies to maximize the use of all biomass components.

Contents

1. Introduction

In the last decade, biomass use for the production of modern bioenergy and biomaterials grew significantly in order to oppose the depletion of fossil resources (and associated increasing energy prices) and to reduce greenhouse gas (GHG) emissions [1]. For both energy and material application of biomass, it is expected that this growth will continue or even accelerate. For example, the Intergovernmental Panel on Climate Change (IPCC) reviewed recent literature and scenarios on long-term biomass deployment potentials and biomass demand for bioenergy [2,3]. In 2008, global bioenergy use accounted for a primary biomass supply of 50 exajoule (EJ_p) per year. By 2050, the global biomass demand for bioenergy is projected to reach about 77 EJ_p/year in the absence of climate policies (median case of baseline scenarios) and about 155 EJ_p/year under the most stringent GHG mitigation scenarios [3]. In addition, Saygin et al. [4] estimate an economic potential of

biomass use of almost 20 EJ_p/year for substitution of synthetic organic material in the chemical industry in 2050. Hence, a total biomass supply of 100–175 EJ/year would be required to meet the projected demand for both bioenergy and biomaterials in 2050. By the same year, the technical biomass deployment potential is estimated to be in the range of 100–300 EJ_p/year [2].

The increasing demand for biomass will intensify the competition between biomass feedstocks as well as their applications; not only between food and non-food uses, but also between non-food applications for energy and materials. Thus, to ensure sustainable expansion of biomass use, we need insight in which routes (biomass value chains) are the most promising for producing heat, power, fuels and materials in terms of their technological, economic and environmental performance. This requires (i) a clear view on the status and prospects of potential value chains; and (ii) assessment and comparison of their economic and environmental performance in the short and longer term. Assessment of the

performance over time is important, because biomass value chains are in different stages of development and have different potentials for improvement. For example, on the short term, new technologies may be more expensive than established technologies. But, as capacity deployment increases, with technological learning, they could become cheaper in the longer term. Key indicators for the economic and environmental performance of biomass value chains are levelized production costs, avoided greenhouse gas emissions and GHG abatement costs. Although these aspects have been assessed widely in the literature, earlier (review) work mainly considers bioenergy, and especially biofuels [5–8]. This literature generally considers either environmental or economic aspects [5,7–10]. In addition, most studies that consider biomaterials focus on environmental impacts (see, e.g., [11–13]), while the number of economic assessments is limited [14,15]. Comparative work between bioenergy and biomaterials only includes environmental aspects [16] or biomass use in the manufacturing sector [17]. However, as energy and material applications in different sectors are competing for biomass feedstocks, only an assessment that includes both their economic and environmental impact can generate better insight in the overall performance of the various biomass value chains. Finally, for various bioenergy systems and their components, the literature has analyzed the role of technological learning in historical cost developments [18–20]. For a good understanding of economic improvement potentials over time, and of potential speeds of technological development and deployment, these insights need to be included in a comparative assessment.

In order to address some of the shortcomings identified in the existing literature, the aim of this article is to evaluate existing and potential biomass value chains for heat, power, fuels and materials. This includes a review of the current status and prospects of these biomass value chains, an assessment of current and projected levelized production costs and GHG emission reductions, and a comparison of the GHG abatement costs of these chains for different time frames.

The remainder of this paper is organized as follows. In Section 2, we explain the methodology of our review and assessment. We discuss the status and prospects of existing and novel biomass value chains in Section 3. Next, we present collected cost and GHG emission data in Section 4, and select a number of biomass value chains for further comparison. In Section 5, we present the results and perform a sensitivity analysis. We discuss important assumptions and limitations in our work in Section 6, and draw conclusions in Section 7.

2. Methodology

Our work examines four components of the biomass value chains: biomass production, feedstock pretreatment, transportation and conversion. First, we describe the options for each component (e.g. different conversion technologies) and the status and prospects of these options based on a literature review. Second, we collect cost and GHG emission data for all components of the biomass value chain as well as for the fossil reference chains, all based on literature review. The review includes data for both the present level of technology and projections for 2030. Third, we define biomass value chains by selecting an option for each of its components. By using the cost and emission data from the preceding review, we calculate and compare the levelized production costs, avoided emissions and GHG abatement costs of these value chains and their fossil reference.

Regarding feedstock production, we also consider yields in various geographical regions. In addition, we assess the potential effect of technological learning on future cost developments. Direct comparison of the levelized costs and GHG emissions requires a uniform functional unit, e.g. the unit of input biomass

or the unit of output. Because we consider diverse products with different functions and from different feedstock types (including agricultural and forestry residues), we cannot select one common functional unit [21,22]. Therefore, we first evaluate the levelized production costs and GHG emissions (per gigajoule (GJ) or tonne product) in relation to the levelized costs and GHG emissions of the fossil equivalent products, respectively. Thereafter, we compare the different value chains by calculating their avoided GHG emissions per hectare (tonnes of carbon dioxide equivalent (tCO_2-$eq_{avoided}$) per hectare (ha)) and GHG abatement costs (in real 2005 US Dollars ($US\$_{2005}$) per tCO_2-$eq_{avoided}$). We make all calculations on the basis of higher heating values (HHV).

The explicit inclusion of co- and/or by-products is an important methodological aspect in calculating levelized costs and GHG emissions of e.g. combined heat and power production (CHP) or biodiesel production with glycerin as a by-product. In the scientific literature, system expansion is a commonly used and generally preferred allocation method [23,24]. To calculate levelized costs, we apply system expansion by taking into account a revenue for by-products (for CHP, we consider heat as a by-product). We only collect GHG emission data from life-cycle inventory studies that apply system expansion.

2.1. Cost data standardization

In order to make a fair comparison, we standardize the collected cost data and calculate levelized production costs. We perform the following procedure:

Indexation: We convert cost data to $US\$_{2005}$ using gross domestic product (GDP) inflators [25] and annual currency exchange rates [26].

Feedstock cost: We choose an average cost to deliver the biomass feedstock to a conversion plant in the selected region, based on our review work. For the fossil reference chains, we use present and projected fossil resource price data as approximation of the delivery costs.

By-product revenue: We choose a fixed by-product revenue for each by-product type, based on values found in the literature.

Calculation of levelized cost. We apply the methodology as described and used in Bruckner at al. [27]:

$$LCOP = \frac{\alpha \cdot I + OM_{fixed} + OM_{var,non\,feed} + F - R}{P} \quad (1)$$

$$\alpha = \frac{r}{1 - (1+r)^{-L}} \quad (2)$$

where *LCOP* is the levelized cost of product [\$/GJ product or \$/t product]; α is the capital recovery factor [%/yr]; *I* is the investment cost [\$]; OM_{fixed} is the fixed annual operation cost [\$/yr]; $OM_{var,non-feed}$ is the non-feed variable operation costs [\$/yr]; *F* is the feedstock cost [\$/yr]; *R* is by-product revenue [\$/yr]; *P* is the annual production [GJ product or tonne product per year]; *r* is the annual discount rate (7%); *L* is the economic lifetime [yr].

The fixed annual operation costs (OM_{fixed}) consist of labor, maintenance, plant overhead and insurance. Variable operating costs are composed of feedstock costs (*F*), by-product revenues (*R*), and non-feed variable operating costs ($OM_{var,non-feed}$), which include utilities, auxiliaries and catalysts. In order to reflect the varying lifetimes and capacity factors in actual conversion facilities, we do not standardize these parameters.

We calculate levelized costs for all biomass value chains, and for heat, power and material production from oil, natural gas and coal. For fossil gasoline and diesel, we use the wholesale gasoline and diesel fuel prices as the surrogate for the gasoline and diesel fuel production costs. We adopt the methodology from the US Environmental Protection Agency [28] to estimate how the crude

Fig. 1. Main routes from biomass to bioenergy and biomaterials discussed in this article.

oil price affects the wholesale gasoline and diesel prices:

$$COG = (P_{oil}2.65) + 27 \qquad (3)$$

$$COD = (P_{oil}3.38) - 11.7 \qquad (4)$$

where *COG* and *COD* are the cost of gasoline and diesel [US ¢/gallon], respectively, and P_{oil} is the crude oil price [$/bbl].

2.2. Avoided GHG emissions and GHG abatement costs

To calculate avoided GHG emissions, we collect GHG emission data from life-cycle inventories which include all activities from resource extraction (cradle) to final end use (grave),[3] and cover both direct and indirect emissions (i.e. emissions that are a result

of the consumption of purchased materials and energy, and of upstream activities such as the production and transport of purchased materials and energy). We use the data without any harmonization in background assumptions. Effects of direct and indirect land use change (DLUC and ILUC) are space and time dependent and case specific [29,30]. As we want to compare the biomass value chains on a more general level, we exclude LUC induced GHG emissions from our analysis, but we consider this topic in our discussions. To calculate GHG abatement costs, we apply the methodology as described and used in Damen et al. [31]:

$$GHG \text{ abatement cost} = \frac{LCOP_{bio} - LCOP_{ref}}{m_{GHG,ref} - m_{GHG,bio}} \qquad (5)$$

where *LCOP* is the levelized cost ($/GJ or $/tonne) and *m* the GHG emission factor (tCO_2-eq/GJ or tCO_2-eq/tonne) of the biomass (*bio*) and reference (*ref*) chain.

The calculations of levelized costs, avoided emissions, and GHG abatement costs can be found in the supplementary material.

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[3] For bio-materials, it is assumed that these are transported to waste-to-energy-facilities after their end of life and that they are incinerated without energy recovery.

2.3. Sensitivity analysis

We apply a sensitivity analysis to evaluate how GHG abatement costs are affected by feedstock costs, fossil energy prices and annual discount rates.

3. Chain description

Many possible compositions exist for biomass value chains (Fig. 1). In this section we discuss the status and prospects of the different options for feedstock production, logistics, pre-treatment and conversion.

3.1. Feedstocks

A wide range of feedstocks is used for the production of bioenergy and biomaterials. Heat and power systems rely mostly on wood (e.g. logs, sawdust), and residues and wastes from agriculture, food processing and municipal solid waste (MSW) [6]. Sugar, starch and oil crops are currently the main feedstocks for (liquid) biofuels and for biomaterials [6,32]. Other feedstocks that are expected to become important for the production of biofuels and biomaterials are dedicated energy crops, including short rotation crops (SRC, e.g. willow, poplar, eucalypt) and perennials (switchgrass, miscanthus), and lignocellulosic wastes and agricultural and forestry residues [33,34]. In addition, organic residues like manure are applied for the production of gaseous biofuel. Aquatic biomass is potentially a highly productive source of oil (microalgae) or polysaccharides (macroalgae). Yet, the technology and process chain need substantial improvement before commercial production can be economically feasible [35].

The technical supply potential of biomass resources depends on numerous factors. Agricultural and forestry residues and organic wastes ultimately depend on the demand for conventional agricultural and forestry products and on ecological considerations. Based on literature review, Chum et al. [2] estimate that these resources have prospects to provide between 25 and 280 EJ/yr by 2050. For the same year, the technical potential for conventional agricultural crops and dedicated energy crops ranges from 0–810 EJ/yr [2]. The potential is mainly determined by land availability (and suitability) and biomass yields (for current and projected yields, see section 4.1). While conventional crops are especially suitable for cultivation on agricultural land, dedicated crops are also considered to be suitable for cultivation on marginal and degraded lands [34]. Microalgae are cultivated in open ponds or closed photobioreactors (PBRs), and thus do not compete for arable land [35].

3.2. Biomass logistics

When feedstock production and conversion are located in the same country, the raw feedstock is directly transported to the conversion plant or to an intermediate storage facility, from where further distribution takes place [28]. For corn in the USA, for example, the feedstock transport distance from the farm to the ethanol plant is below 80 km [19]. In Indonesia, oil palm mills are located close to the cultivation areas, and crude palm oil is transported to biodiesel plants that are more distant [36]. In contrast, wood pellets for power and heat production are traded over long distances. These pellets are mainly transported from Canada, the USA and Europe to the USA and Europe. The main transport modes are ocean freight, short sea shipping and truck transport [37].

National and international trade of biomass feedstocks, especially of pellets, has expanded in recent years [38]. As a result of the introduction of lignocellulosic biomass for biofuels and biomaterials, Latin America and Sub-Saharan Africa are considered to be potential large net exporters of biomass and international trade is expected to play a pivotal role in further development of the biomass sector [39,40]. Optimization of international freight costs and of storage and handling at seaports are key prerequisites to achieve low-cost feedstock supply [38].

3.3. Biomass pretreatment technologies

As handling and (long distance) transport of raw biomass is inefficient and economically unattractive, pretreatment or densification is applied. At biofuel plants, pretreatment basically refers to mechanical treatment (e.g. milling) of the feedstock to clean and size the biomass and to destroy the cell structure. Below, we discuss pretreatment technologies that aim at efficient and cheap transport of feedstocks. Due to growing international trade, the importance of these technologies will increase in the future [40].

3.3.1. Chipping, briquetting and pelletization
Chipping, briquetting and pelletization are widespread methods to pretreat wood resources. When chipping, the feedstock is reduced in size. During briquetting or pelletization, biomass is compressed and extruded in screw or piston presses [2]. Compared to chips, briquettes or pellets have a uniform size, and moisture and heat content, which enhances handling [41]. Pellets have a higher heating value (HHV) of about 20.5 GJ/t_{dm}, compared to 19.5 GJ/t_{dm} for chips [42]. For pelletization, Uslu et al. [43] report a net energetic efficiency of 84–88% (LHV).

Most pellet plants are located in Europe, Canada and the USA. These plants purchase their feedstock from nearby or adjacent sawmills, or from the logging industry [44,45]. Briquetting plants can usually be found in India and Thailand, and use a range of byproducts from the food and forest processing industry (secondary residues). Chips are generally produced from wood waste, as a byproduct of conventional forestry [2].

3.3.2. Torrefaction
Torrefaction is the anaerobic heating of biomass at temperatures between 200 and 300 °C. During the process, the feedstock loses water but maintains 90% of its original energy content [46]. Torrefied biomass is a solid uniform product with an HHV of 20–24 GJ/t_{dm} [43]. But, it is also a porous product with a low volumetric density, and further densification is desirable. Torrefaction combined with pelletization (TOP) is considered to be an attractive option. Torrefaction technology is in the demonstration phase [43,47]. Plants that have been built at the commercial scale are not operating at full capacity yet [48]. The net efficiency (LHV) is 92% for torrefaction and 90–95% for TOP [43].

3.3.3. Pyrolysis & hydrothermal upgrading
Under anaerobic conditions and at a high temperature (500 °C), biomass decomposes into liquid bio-oil, charcoal (biochar) and a mixture of gas (syngas). A distinction can be made between slow and fast pyrolysis, depending on the residence time in the reactor. Biochar production is maximized by slow pyrolysis, and bio-oil production by fast pyrolysis [6]. Because bio-oil has a higher energy density compared to pellets and torrefied biomass, fast pyrolysis is considered to be an attractive pretreatment technology [6]. The net efficiency (LHV) of pyrolysis is 64% [43].

Bio-oil can also be produced by hydrothermal upgrading (HTU, also hydrothermal liquefaction). At high pressure (120–200 atm), a temperature of 300–400 °C and in the presence of water, biomass is liquefied [6]. While slow pyrolysis is commercially applied throughout the world, fast pyrolysis is an early commercial technology [49,50]. HTU technology is in the demonstration phase. Commercial application of pyrolysis and HTU bio-oil is closest to being realized in heat and power generation. In addition, research activities consider different routes for bio-oil upgrading to biofuels such as diesel, gasoline and kerosene [6,43,49]. Biomass feedstock for pyrolysis and HTU will mainly be lignocellulosic material, but also algal lipids could be converted to bio-oil by these technologies.

3.4. Biomass conversion technologies

Fig. 2 shows the development phases of biomass conversion technologies for heat, power, fuels and materials. This overview is not meant to be exhaustive, but gives an overview of possible technologies that are regularly considered in the literature. Especially with regard to biomaterials, the options are numerous. Below, we discuss the current status and prospects of the most important technologies.

3.4.1. Heat and power

A wide variety of heat and power generation routes are available, which can be classified into dedicated combustion (biomass feedstock only), cofiring, gasification and anaerobic digestion. These routes are applied for heat or power only, as well as for CHP (also called co-generation). Cogeneration is mainly applied to increase the overall efficiency of power production. CHP plants play a significant role in the production of heat and power, and it is expected that they will maintain this position in the future [2,6].

3.4.1.1. Dedicated combustion. The leading technologies in dedicated biomass combustion are pellet boilers or chip burners. These firing systems are commercially applied to produce hot water or steam. Main applications are domestic and district heating, and power and CHP generation [41,54]. In the case of power or CHP production, biomass combustion is combined with a steam cycle. The produced steam is pressurized and expanded in a steam turbine. The steam turbine converts the thermal energy into rotary motion. At present, typical capacities are 5–100 kW_{th} for domestic heating, 0.5–5 MW_{th} for district heating, and 2.5–100 MW_e for steam cycle technologies [[8,54]; [55] in:[27]]. Domestic and district heating (including both heat and small-scale CHP production) is mainly employed in Scandinavia and Austria. Steam cycles are widely applied in stand-alone power plants and in the pulp and paper industry, which derives process heat from waste incineration [56]. At the mentioned capacities, investment costs are 300–1200 $/$kW_{th}$ for domestic heating, and 500–800 $/$kW_{th}$ for district heating. For power and CHP systems, the investment costs are 1850–6200 $/$kW_e$ (all for wood chips and pellets) [[54,57]; [8,55] in:[27]]. The thermal efficiency for domestic and district heating is 79–88% [54,57], the electric efficiency for power and CHP is 18–28% [[8];[55] in:[27]]. Combustion of MSW instead of wood pellets results in higher investment costs and a lower efficiency [54]. In addition, two types of direct combustion boiler systems can be distinguished on the basis of how the feedstock is fed into the boiler: fixed-bed (stoker) and fluidized-bed [41]. However, investment cost data for power generation does not significantly differ between these two systems [[58];[55] in:[27]].

Other power or CHP technologies based on dedicated biomass combustion are the Stirling engine and Organic Rankine Cycle (ORC). The ORC works analogous to the steam cycle, but uses an organic fluid instead of water. This fluid has a lower boiling point and allows for low temperature heat conversion to mechanical power [6]. The Stirling engine uses combustion heat to directly heat a gaseous working fluid in the engine. Both technologies are in the demonstration phase [6]. Because of the relatively small capacity of 50 kW_e–1.6 MW_e, these technologies show good potential for domestic or distributed cogeneration [6]. The investment costs, however, are currently very high at 5800–9800 $/$kW_e$ [[54]; [8] in:[27]]. Also, current electric efficiencies are 9–16%, and improvement is needed [6,8,54].

3.4.1.2. Cofiring. Cofiring, or co-combustion, mostly involves combustion of biomass and pulverized coal [6]. Currently, direct cofiring is successfully applied in existing coal furnaces for power or CHP production. The scales of these plants range from 5 to 100 MW_e. The electrical efficiencies are relatively high, 26% for CHP and 36–41% for power, and investment costs are low at about 200–500 $/$kW_e$ [[54,56];[55] in:[27]]. The major bottleneck is the biomass cofiring ratio, which is limited to 5–10%. An important reason is that biomass ashes differ from coal ashes. Deposition of biomass ashes on surfaces in the boiler and in catalysts affects the efficiency of the plant [6]. Technologies that avoid this issue are parallel and indirect cofiring. Parallel cofiring involves biomass combustion in a separate boiler, while the produced steam is inserted into the main steam circuit of the coal plant. This technology is in the stage of early commercialization [6]. Through indirect cofiring, gasified biomass is cleaned-up to so-called syngas which is combusted with (pulverized or gasified) coal or natural gas [6,59], see the discussion about gasification below. Indirect cofiring systems are in the demonstration phase [6,41]. Parallel cofiring requires 2–4 times higher investment costs compared to direct cofiring; for indirect cofiring this factor is even higher [[7,8,54];[55] in:[27,58]].

3.4.1.3. Gasification. Gasification occurs when biomass is heated with a sub-stoichiometric amount of oxygen, resulting in partial oxidation of the biomass [2,6]. If the gasification is performed at 900–1000 °C a mixture of hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2), water vapor (H_2O), as well as methane and tars is obtained (product gas). If air is used as oxygen source, large amounts of nitrogen (N_2) are also present. If gasification is performed at > 1500 °C a gas mixture of mainly H_2, CO, and also CO_2 and H_2O is obtained (syngas). This is always performed with enriched or (almost) pure oxygen. Syngas can also be obtained by cleaning the product gas. Although both product gas and syngas can be used for heat and power production, product gas is preferred because of the higher energy efficiency of low-temperature gasification compared to syngas production. In general, the preferred technology for power production is atmospheric circulating fluidized bed (CFB) gasification [59].

Most gasifiers use wood and other lignocellulosic biomass, but can also be designed to convert other biomass materials and municipal waste [59]. Commercial technologies burn the product gas directly in a boiler to (co-)produce steam. These systems can be applied for, for example, district heating [41]. Another option is to combust the product gas in an internal combustion engine (ICE), which is either a gas turbine or a gas engine, to produce power or CHP. These plants are in the R&D and demonstration phase [6,41]. A technology based on this concept is the Integrated Gasification Combined Cycle (IGCC), in which a steam boiler and steam turbine use exhaust heat from the gas turbine to generate additional electricity [58,59]. The main advantage of power and CHP production through gasification, compared to dedicated biomass combustion, is the higher electric efficiency of 28–34% for gas engines and 40–45%

		R&D	Demonstration	Early commercial	Commercial
Heat	Combustion				Domestic/district/industrial
	Gasification		Small scale gasification		
Power/CHP	Combustion		Stirling engine	ORC	Steam engine
	Anaerobic digestion				Steam cycle
					Landfill gas
					Manure digesters
	Gasification	Gas turbine	Gas engine	Steam cycle	
		IGFC	IGCC		
	Cofire		Indirect	Parallel	Direct
Fuels	Fermentation	Lignocellulosic to ethanol			Sugar & starch to ethanol
	Esterification	Biodiesel from microalgae			Biodiesel
	Hydrogenation	Renewable diesel from microalgae		renewable diesel	
	Anaerobic digestion		Biogas upgrading (methane)		Biogas
			Biogas reforming (hydrogen)		
	Gasification		FT (diesel)		
			Catalytic synthesis:		
			SNG, hydrogen	methanol	
Materials /chemicals	Fermentation	PA6 & PA66		PTT, PHA	PLA
					Ethylene
					(Butanol[a])
				Ethylene derivatives:	
			PP, PVC		PE, PET
	Lignin processing	aromatics			
	Esterification			ECH	
	Polyol polymerization				Lubricants, polymers, surfactants
	Direct modification of natural polymers				Cellulosic polymers
					Starch plastics
	Gasification	FT (olefins)		MTO (olefins)	
Combined / Biorefinery products	Integrated technologies	Biorefinery			

Fig. 2. Development phase of biomass conversion technologies for energy and materials. Adapted from Bauen et al. [6] and Chum et al. [2], with information from [14,32,41,51–53]. [a]Fermentative production of butanol has been commercially applied in the past, but has ceased. R&D, research and development; ORC, organic ranking cycle; AD, anaerobic digestion; IGFC, integrated gasification fuel cell; IGCC, integrated gasification combined cycle; FT, Fischer–Tropsch; SNG, substitute natural gas; PTT, polytrimethylene terephtalate; PHA, polyhydroxyalkanoates; PLA, polylactide; PP, polypropylene; PVC, polyvinylchloride; PE, polyethylene; PET, polyethylene terephtalate; ECH, epichlorohydrin; MTO, methanol-to-olefins.

for an IGCC [8,54,59]. However, the presence of contaminants in the product gas (e.g. tars, nitrogen, chlorine compounds) requires a certain degree of gas cleaning (depending on the type of feedstock and gasifier), which proves to be a technological challenge [59,60]. Cost estimations (e.g. in [8,54,61,62]) suggest that gasification can attain lower investment costs compared to dedicated biomass combustion. Yet, initial investments are high and make the commercialization of demonstration plants difficult [56,59]. Also, upscaling of low temperature CFB gasification has only limited effect on the investment costs (the amount of circulating bed material has to be increased). Because of these technological and economic hurdles, Kirkels and Verbong [59] expect that commercialization of the IGCC will be very difficult. Indirect cofiring is considered to be a more feasible option, because of lower requirements for gas cleaning and lower costs [59].

3.4.1.4. Anaerobic digestion. During anaerobic digestion, organic matter undergoes biological degradation in the absence of oxygen or air. Biogas, the main product of anaerobic digestion, is a gas mixture of methane (CH_4) and carbon dioxide (CO_2) [6]. Biogas combustion technologies for power and CHP production are similar to syngas combustion [2,6]. Commercial biogas production takes place in biodigestors or through landfill gas recovery. Anaerobic digestion in biodigestor units is mainly related to agricultural activities and is employed in a large scale in China and Germany. Recovery of landfill gas is successfully applied in mainly the UK, Spain and Italy [6]. Investment costs for CHP production based on anaerobic digestion in biodigestors range from 2500 $/$kW_e$ at 3.4 MW_e to 5100 $/kW_e$ at 0.3 MW_e, which is lower than gasification at similar scales. But, electric efficiencies are lower as well (13–19%) [57]. A large variety of biomass

materials, both wet and dry, can be applied to anaerobic digestion. Lignocellulosic biomass, however, is not suitable for anaerobic digestion because the component lignin is not biodegradable [2,6].

3.4.2. Fuels

Current commercially applied biofuel production plants are based on so-called first-generation technologies and biomass feedstocks. These include ethanol from the fermentation of sugar and starch crops, biodiesel from transesterification of vegetable oils, and biogas production through anaerobic digestion. Also the production of renewable diesel by hydrogenation of oils and fats is considered to be a first-generation technology. In many projections, including the WEO scenarios [63], these first-generation feedstock and conversion technologies will mainly represent the biofuel production in the next decade. In 2030, however, second-generation feedstocks and technologies are projected to achieve a share of 60% in the total biofuel production [52,63]. Second-generation technologies use lignocellulosic feedstocks, applying hydrolysis and fermentation to ethanol, gasification and processing to various biofuels or pyrolysis to pyrolysis oil and other fuels.

3.4.2.1. Fermentation (+hydrolysis). The leading technologies in biochemical fuel production are the fermentation of monosaccharides (C6 sugars) and of the polysaccharide starch. These technologies are commercially applied, mainly to produce corn-based ethanol in the USA and sugarcane ethanol in Brazil. Ethanol is used as a gasoline substitute, and minor shares of ethanol can be blended with gasoline without the need for modifications to the vehicle [6]. At present, fermentation units have capacities up to 550 MW_{feed} for corn and up to 1000 MW_{feed} for sugarcane. Ethanol

production from sugarcane, however, is often combined with sugar production and only about 50% of the feedstock is converted to ethanol [18,64]. During the fermentation process, microorganisms like yeast and bacteria metabolize sugars obtained from the feedstock [2]. C6 sugars can easily be extracted from sugar crops. Starch, however, first needs to be depolymerized through hydrolysis, an enzymatic conversion process [2,65]. For corn ethanol production, a distinction can be made between dry and wet milling processes. Most corn ethanol plants apply dry milling, in which the corn grain is milled mechanically, and the complete milling product is fed into the hydrolysis and fermentation process. In wet milling, the corn is soaked in a mixture of water and SO_2, which allows for separation of the kernel components. Hydrolysis and fermentation are then only applied to the starch stream [64]. Currently, the investment costs for large-scale conversion are about 160 $/kW$_{feed}$ for corn (dry milling) and 100 $/kW$_{feed}$ for sugarcane. Costs and efficiencies can be improved through the co-production of electricity from feedstock processing residues.

An alternative option to biochemically produce ethanol is the fermentation of lignocellulosic feedstock. This process is more complex compared to conversion of sugar and starch feedstocks. Currently, the production of lignocellulosic ethanol is explored and demonstrated at pilot, demonstration and commercial scales [66]. First, a pretreatment process (e.g. hydrolysis or steam explosion) separates the biomass into cellulose, hemicellulose and lignin. This is followed by acid or enzymatic hydrolysis of the cellulose, which consists of long chains of C6 sugars. Hemicellulose contains a mix of C5 and C6 sugars and is easier to break down than cellulose. Finally, the C5 and C6 sugars are fermented. Lignin is not a carbohydrate and cannot be hydrolyzed and fermented. Yet, it can be combusted for power co-generation [56,65]. The major bottleneck is the pre-treatment of the feedstock, which is relatively expensive and inefficient. To make the production process more efficient and cost-effective, existing processes are improved and novel processes are developed [6,56,66,67]. Also, options for process integration are investigated and developed [6,66,67]. The most mature configuration, which is now in the demonstration phase, is called Separate Hydrolysis and Fermentation (SHF). In SHF, all hydrolysis and fermentation steps take place in separate reactors. Simultaneous Saccharification and Fermentation (SSF) combines hydrolysis with the fermentation of C6 sugars. In Simultaneous Saccharification and Co-Fermentation (SSCF), hydrolysis and co-fermentation of C5 and C6 sugars take place simultaneously in one reactor. Consolidated Bioprocessing (CBP) combines all processes, including enzyme production, in a single vessel. It is considered to be the endpoint in the evolution of biomass conversion technology. Due to the level of development, SHF, SSF and SSCF may be commercialized in the short (< 5 yr) or medium term (5–15 yr). CBP will only be attainable in the longer term [6,67]. Investment costs are estimated to be 500–700 $/kW$_{feed}$ for near-term commercial plants (SHF, SSF and SSCF) [7,28,60] and 240–510 $/kW$_{feed}$ in 2030 [54,60]. Much effort is also made in the development of biorefineries, which co-produce other energy and material products next to ethanol (see Section 3.4.4 for a discussion on biorefineries) [66].

3.4.2.2. Transesterification.
Transesterifcation is the major commercial chemical process to produce biofuels from vegetable oils and animal fats. The vegetable oils contain triglycerides. During transesterification, the triglycerides react with alcohols (often methanol) to form an alkyl ester of fatty acids. These esters are referred to as biodiesel. Glycerin is formed as byproduct [2,6]. Present biodiesel plants have maximum production capacities of more than 400 MW$_{feed}$. At these capacities, investments costs of 160 $/kW$_{feed}$ can be attained [7,27]. Biodiesel can

be blended with fossil-based diesel at a blending rate of at least 20% biodiesel without modifications to the vehicle's engine or fuel system [6]. As an alternative to vegetable oils, algal oil is considered to be a potential (third-generation) feedstock in the future [28].

3.4.2.3. Hydrogenation.
An alternative to transesterification, hydrogenation (or hydrotreating) is a chemical process that produces renewable diesel. The process involves the reaction of vegetable oils and animal fats with hydrogen [6]. An alternative feedstock is bio-oil derived from pyrolysis or hydrothermal liquefaction, which enables the application of second- or third-generation biomass feedstocks as well. Hydrogenation is applied at the commercial scale, but development and deployment are at an earlier stage than transesterification [68]. The production costs are potentially lower compared to transesterification. Bain [7] reports investment costs of less than 70 $/kW$_{feed}$ at a production capacity of about 120 MW$_{feed}$. Renewable diesel is chemically similar to fossil-based diesel, making blending possible in any proportion [6].

3.4.2.4. Anaerobic digestion.
Biogas from anaerobic digestion can be upgraded to methane or reformed to hydrogen. Biomethane (or substitute natural gas, SNG) complies with natural gas standards and can be injected into the natural gas grid and/or used as transport fuel [6]. Several technologies for biogas upgrading are commercially available (e.g. pressure swing absorption and water scrubbing), while other technologies like cryogenic upgrading are at earlier stages of development [2,6,69]. Most upgrading plants are located in Europe, where capacities mainly range between 100 and 1000 Nm^3 biogas/h (0.6–5.6 MW$_{biogas}$). A number of large-scale upgrading plants with capacities up to 13,000 Nm^3 biogas/h (72 MW$_{biogas}$) are located in the USA [69]. Persson [70] reports investment costs of about 600 $/kW$_{biogas}$ at a capacity of 200 Nm^3 biogas/h and of approximately 420 $/kW$_{biogas}$ at 600 Nm^3 biogas/h.

3.4.2.5. Gasification.
After high temperature gasification of (lignocellulosic) biomass or bio-oil, a synthesis process can be applied to convert H_2 and CO from the syngas into biofuels. First, a widely considered technology to produce fuels like diesel, gasoline and kerosene (jet fuel) is Fischer–Tropsch (FT) synthesis [71]. The production of FT diesel, ethanol and also other fuels is demonstrated at pilot to commercial scales [72]. Second, a range of fuels can be produced by catalyzed synthesis, including methane (synthetic natural gas: bio-SNG), methanol, dimethyl ether (DME), ethanol and butanol. A third route is water gas shift and separation to hydrogen [2].

Compared to product gas combustion for heat and power, effective gas cleaning is even more important for the synthesis of biofuels. The issue that current gas cleaning technology is insufficient hinders the commercialization of these conversion processes [59,60,72]. Kirkels and Verbong [59] believe that once clean syngas is available, existing technologies (for fuel production after coal gasification) can be applied to produce biofuels. The investments costs of high temperature gasification are higher compared to atmospheric CFB gasification. Studies by EPA [28], Bain [7] and Hamelinck et al. [60] find short-term investment costs from 500 $/kW$_{feed}$ for ethanol to almost 700 $/kW$_{feed}$ for FT diesel, at production scales of about 400 MW$_{feed}$. To make gasification economically feasible, Kirkels and Verbong [59] state that production scales of more than 1000 MW$_{syngas}$ are required.

3.4.3. Materials
Biomass serves as raw material for a large variety of non-energy products [73]. We distinguish between two product groups. The first covers traditional wood, paper and textile products (e.g. cotton). This

also includes the use of wood as substitute for steel and concrete in construction, which is considered to be an important option to reduce the use of fossil energy and non-biomass materials [74,75]. The second category covers synthetic chemicals produced from biomass feedstock. Some materials have been produced from biomass for decades, e.g. alkyd resins from vegetable oils [76]. Bio-based materials that may replace current petrochemical products or that allow for new applications and markets can be considered as a group of novel biomaterials. In this study, we focus on these new biomaterials. We discuss the production routes for these novel biomaterials in this section.

Today, synthetic organic and inorganic chemicals (e.g. plastics, fibers and nitrogen fertilizers) are produced from a limited number of platforms chemicals (mainly olefins and aromatics, but also ammonia, methanol, carbon black, oxygen and chlorine), see Table 1 [4,77,78]. The largest share of these platform chemicals is produced from hydrocarbon feedstocks (primarily crude oil and natural gas) [79]: in the organic chemical industry this share is 90%, the remaining 10% is derived from vegetable oils and biomass [4]. Olefins and aromatics are the main resource for plastics and fibers. In 2007, plastics and fibers represented about 75% and 13%, respectively, of the product mix in the organic chemical industry [4]. Petrochemical ammonia is the key source for the production of synthetic nitrogen fertilizers [78]. In 2009, about 33% of methanol was converted into formaldehyde, which is used not only for resins but also for other products. Other main uses of methanol are the production of gasoline additives like MTBE (methyl tertiary butyl ether) or as fuel [80]. In many cases, the fossil-based materials can be substituted by a chemically identical bio-based material (Table 1). In addition, it is possible to convert biomass into chemicals and materials that have unique structures and properties [77]. Depending on their material properties, these can be considered as a (partial) substitute for current fossil-based chemicals or they can allow for new applications and new markets [32,73].

In the literature, dozens of materials that can be produced from biomass are investigated [15,32,73,81], see Fig. 3 for some key production routes and examples of products (partly already produced from biomass, partly in development). Many materials, however, are high value added, but low volume materials (e.g. certain engineering plastics). In this section, we will focus on high volume materials like bulk plastics. These will have the most impact on biomass demand, and the largest potential to reduce fossil fuel use and GHG emissions. In addition, many biomaterials and their production processes are too innovative to properly discuss their status and prospects, and to give economic data. Therefore, we limit our discussion to the following conversion technologies: direct modification of natural polymers, fermentation, transesterification, polymerization of natural oils, gasification, pyrolysis, and catalytic conversion.

3.4.3.1. Direct modification of natural polymers. Two important natural polymers present in biomass are starch and cellulose. Natural cellulose is extracted or chemically modified to produce cellulosic polymers [89]. Cellulosic fibers like viscose, modal and tencel are widely produced. In 2008, the global production amounted to 3.0 Mt [90]. Cellulose films like cellophane dominated the packaging field in the past, but lost their market dominance in the 1950s [89]. The production capacity was 36 kt in 2010, and is not expected to increase by 2015 [91,92].

Native starch has some disadvantages like brittleness and poor thermal processability [89]. However, these can be (partially) overcome by thermal, chemical or mechanical processing of the starch. A variety of products can be derived from these processes which are referred to as starch plastics [89]. The production capacity of starch plastics was 25 kt in 2003 and grew to 155 kt

Table 1
Main platform chemicals derived from fossil resources, and their derivatives [32,78,79,82–84].

Platform chemical from fossil feedstock	Global production 2009 (Mt/yr)	Important derivatives[a]	Global production 2009 (Mt/yr)	Chemically identical bio-based counterpart?
Olefins				
Ethylene	112.6	PE	60.0	Yes
		PVC	37.5	Yes[d]
		Ethanol	2.6 (1998)[b]	Yes
Propylene	53.0	PP	27.6	Yes
		Epoxy resins	1.2 (2007)[c]	Yes[d]
		Butanol	2.8 (2004)	Yes
Butylene	20.3 (2004)	MTBE	30.2	Yes[d]
Aromatics				
Benzene	49.2	PS	18.0	No
		PA6/PA66	6.6 (2007)[c]	Yes
		phenol	8.3	
Toluene	19.6	Fuel additives	n/a	Yes
		PUR	12.3 (2007)[c]	No[d]
Xylenes	35.6 (2004)	PET/PBT	12.4	Yes[d]
Other				
Ammonia	152.4 (Mt NH₃)	Urea	147.5	
		Nitric acid	52.3	Yes
Methanol	40.6	Formaldehyde	28.7	Yes
		MTBE	30.2	Yes[d]
		Acetic acid	5.2	Yes
Chlorine	61.2	Epoxy resins	1.2 (2007)[c]	Yes[d]
		PVC	37.5	Yes[d]

PE: polyethylene; PVC: polyvinylchloride; PUR: polyurethanes; PP: polypropylene; PS: polystyrene; PA: polyamide; PET: polyethylene terephthalate; PBT: polybutylene terephthalate; n/a: not available.

[a] Derivatives can be mentioned more than once, because the production of these chemicals often involves the use of different platform chemicals; e.g. PVC (ethylene and chorine), epoxy resins (chlorine and propylene), and MTBE (methanol and butane).

[b] Installed capacity in 1998/1999 [79], fossil synthetic ethanol only; production of bioethanol production for fuel use not included.

[c] Global consumption in 2007 [32].

[d] The bio-based counterparts are partially bio-based chemicals.

in 2007. As a result, starch plastics are one of the most important bio-based plastics in the present market [32,91]. The projected growth in global production capacity from 2010 to 2015, however, is limited to 6% [91,92]. Starch plastics can partially replace fossil-based plastics like poly-ethylene (PE). Yet, based on their technical properties, the substitution potential of starch plastics is estimated to be limited to 5% of the global plastic consumption in 2007 [32].

3.4.3.2. Fermentation. Through fermentation of biomass, not only ethanol but also other chemicals can be produced.[4] Some are suitable for direct end-use application, others serve as building blocks for materials [73,89,93]. Prominent examples that can play an important role in replacing the main fossil-based chemicals identified in Table 1 are:

— *Ethanol*: In addition to the use of bio-based ethanol as fuel, this chemical can also be used for the production of ethylene and other platform chemicals [94].
— *Ethylene*: Ethylene is a building block for a variety of bulk materials (Table 1) [32]. It is produced by catalytic dehydration

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[4] The application of fermentation and enzymatic processes is also called white or industrial biotechnology (in Europe and USA, respectively) [15].
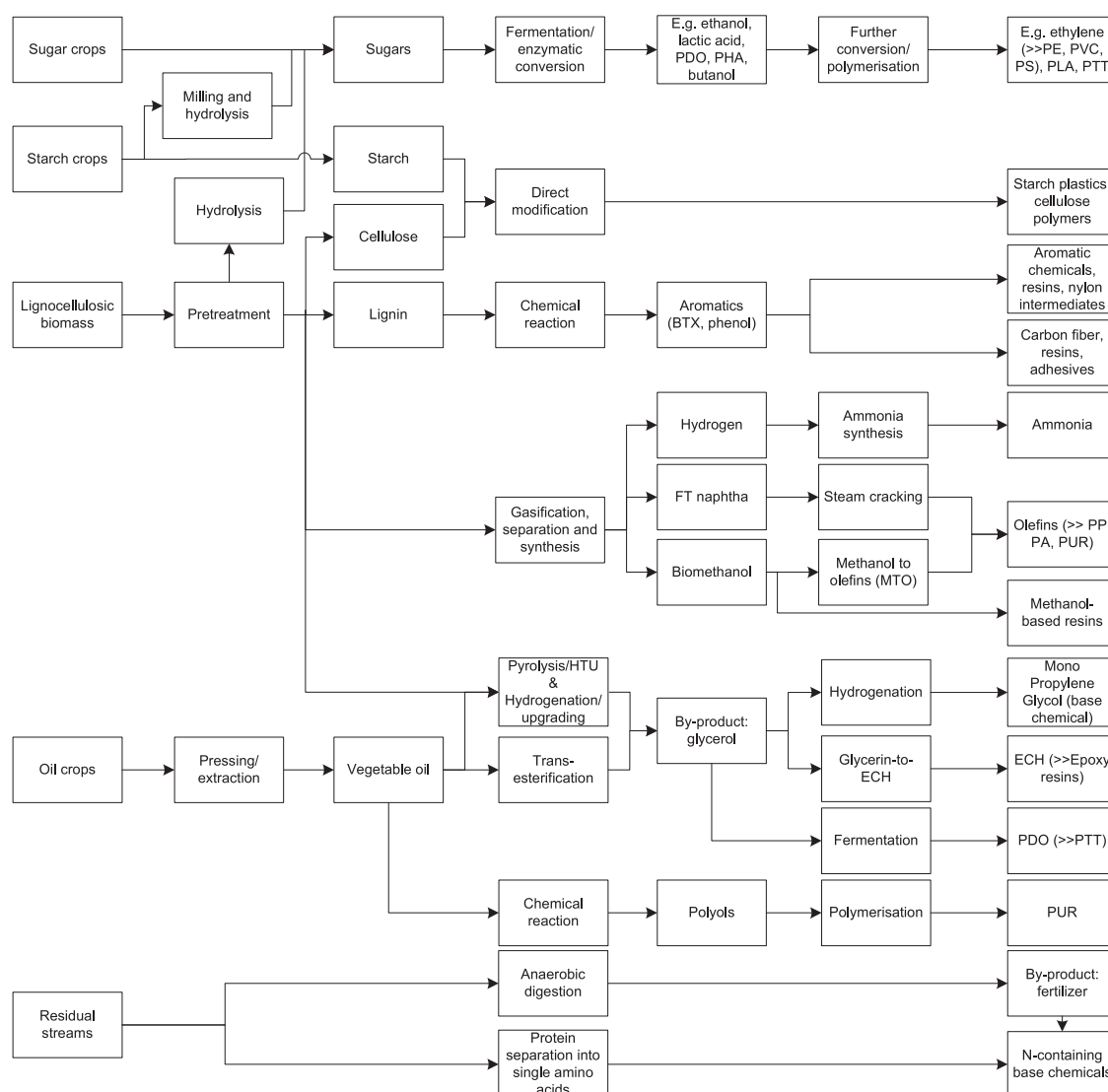
Fig. 3. Possible routes to use different biomass feedstock types to produce materials and chemicals that can substitute current fossil-based chemicals [73,85–88]. PE, polyethylene; PUR, polyurethanes; PP, polypropylene; PS, polystyrene; PA, polyamide; PDO, 1,3-propanediol; BTX, benzene, toluene, and xylenes; PHA, polyhydroxyalkanoates; PTT, polytrimethylene terephtalate; PLA, polylactide; PVC, polyvinylchloride; ECH, epichlorohydrin; MTO, methanol-to-olefins

of ethanol (called ethanol-to-ethylene or ETE) [87]. The production of bio-based ethylene has been commercial in the past, ceased in the early 1990s, but is receiving renewed attention. As the conversion can be carried out via an established technology, bio-ethylene production is already economically competitive in Brazil, where sugarcane prices are low and experience in ethanol production is extensive [95]. Also, biobased PE is already produced on a commercial scale (200 kt in 2010), and applied for packaging [76,91]. The production of other derivatives like PVC is in the stage of demonstration and early commercialization.

– *Propylene*: Propylene is an important platform chemical for materials like polypropylene (PP). Compared to bio-based ethylene, the production of bio-based propylene is technologically more challenging [96]. One production route is metathesis, which is a reaction of ethylene with 2-butylene to form propylene [96]. This is a commercial technology for fossil-based propylene [97]. The Brazilian company Braskem expects to bring an ethylene-based bio-polypropylene plant online in 2013 [98]. The plant will have a production capacity of at least 30 kt/yr [98]. An alternative route may be the production of 2-propanol via fermentation, followed by dehydration (comparable to ETE) [96]. This route is neither very advanced, nor widely explored [77].

– *Butanol*: Butanol is mainly used as solvent and thinner or in plasticizers [73,93]. The fermentative production of butanol was an established process in the first half of the 20th century, but was abandoned because the production from fossil resources was cheaper [93]. In 2007, Haveren et al. [77] expected that the production could become economically viable in 5–10 years.

– *Polylactide* (*PLA*): PLA is formed through polymerization of lactic acid, a direct fermentation product. It can partially substitute fossil-based plastics like PE and PET. PLA is commercially available and is considered to be an important plastic in the future biobased plastic sector [32,92]. European Bioplastics [91,92] projects the production capacity to grow from 113 kt in 2010 to 216 kt in 2015.

– *Polyhydroxyalkanoates* (*PHA*): PHA is a direct product of fermentation, and is a potential substitute for various fossil-based plastics [32]. With an installed capacity of 70–88 kt/yr (2010) the production is still in early commercial stages. Until recently, PHA was expected to be one of the main bioplastics in the next decade [32,92]. This has, however, become uncertain since the joint venture Telles LLC was ended in January 2012 [99,100].

— *Polytrimethylene terephtalate (PTT)*: PTT is produced by poly-condensation of 1,3-propanediol (PDO – a product of biomass fermentation) and purified terephthalic acid (a petrochemical product). The production process of PTT is commercial. The material properties of PTT are similar to PET but have some advantages for certain applications. Currently, PTT is mainly applied in fibers for carpets and textiles [76].

Next to these products, fermentation yields by-products that can be of value for other purposes. Crop residues and by-products from crop processing (e.g. dried distillers grain soluble (DDGS) from corn ethanol production) are rich in proteins. The amino acids that form these proteins are only found in biological sources, and are a potential source for nitrogen-containing chemicals like polyamides and urea, which is used for fertilizers [85,101,102]. Besides, the biological wastes could be utilized in anaerobic digestion; the digestate can be applied as fertilizer. Finally, lignocellulosic biomass contains lignin. Lignin cannot be fermented and is primarily used for power generation. However, as the building block molecules of lignin are of aromatic nature, lignin is considered as a source for high volume production of bio-based aromatics and aromatic-based chemicals [73,77].

3.4.3.3. Transesterification. The transesterification of (vegetable) oils to biodiesel produces an important by-product: glycerol. Glycerol is considered to be a base chemical for other chemicals and materials. First, epoxy resins (thermosets) can be derived from epichlorohydrin (ECH), which is made via a glycerin-to-ECH process [32]. Besides, ethylene glycol and propylene glycol can be derived from glycerol and converted to alkyd resins or the olefins ethylene and propylene [77]. Another route is the fermentative process to PDO, which can be used as building block for polymers like PTT [93]. Different companies have announced to start up ECH plants in 2012 with a combined capacity of 300 kt refined glycerin [103].

3.4.3.4. Polymerization of natural oils. Natural oils that contain two or more hydroxyl (–OH) groups are called natural oil polyols (NOPs) [76]. Castor oil is one of the few vegetable oils that contain these hydroxyl groups by nature. Other oils, like soy, rapeseed and sunflower oil, can be converted to polyols by a chemical reaction [76]. Currently, the production and application of NOPs take place on a commercial scale [76]. Also, the production of alkyd resins from polyols is an established process. A more recent application of polyols is the production of partially bio-based polyurethanes (PUR) [76,104].

3.4.3.5. Gasification. In the petrochemical industry, CO and H_2 from syngas have a high economic significance as a synthetic component for the manufacture of important intermediates like ammonia, methanol and acetic acid [79]. The interest in gasification for biochemicals focuses on the production of olefins and methanol [105,106]. We distinguish between two routes. The first option is FT synthesis, which not only produces liquid fuels but also FT naphtha (up to 30%). FT naphtha can be converted to olefins by steam cracking, which is applied at a large scale in the petrochemical sector [107]. The second route is catalyzed synthesis of the syngas to produce methanol. The methanol can be converted to olefins [107]. Currently, thermochemical production of bio-based methanol from glycerin is commercially applied [106]. Recently, the first industrial methanol-to-olefins (MTO) production units (where methanol is produced from natural gas or coal) were put into operation. Activities aiming at commercialization of thermochemical biomass conversion are not linked yet to the production of olefins [95].

3.4.3.6. Pyrolysis. As we discussed in Section 3.3, pyrolysis not only produces bio-oil but also biochar. The biochar contains a large amount of nutrients and is considered to be an interesting resource for fertilizer production [50].

3.4.3.7. Catalytic conversion. Many chemical reactions are catalytic conversions, i.e. a catalyst is used – but not consumed – to augment the reaction. Examples of catalytic conversions mentioned earlier in this section are the conversion of ethanol to ethylene, depolymerization of lignin (in R&D), and methanol production from syngas. The number of catalytic reactions to produce chemicals from biomass and bio-based components is large, see for example [94,108]. One interesting option is the production of furans from cellulose and hemicellulose fractions of biomass. Furans (e.g. furfural) are considered as aromatic building blocks for polymers and as precursors for hydrocarbon fuels like diesel and jet fuel [76,108].

3.4.4. Biorefinery

Biorefinery is defined as "the sustainable processing of biomass into a spectrum of marketable products (food, feed, materials, chemicals) and energy (fuels, power, heat)" [109]. The biorefining facility integrates different conversion technologies to maximize both the use of all biomass components and the displacement of fossil resources. Also, the combined production of high volume, low value energy products and lower volume, high value chemicals improves the cost effectiveness of biomass processing [73,110,111]. Elements of the biorefining concept are already used in many of today's biomass converting industries. The co-production of ethanol and animal feed from sugar and starch crops, or the co-production of biodiesel, glycerol and animal feed from oil crops are well-established [109]. IEA Bioenergy task 42 on biorefineries [109] expects that a variety of biorefineries will be introduced in the short term by valorizing side products in existing biomass conversion plants. New, advanced biorefinery concepts that are now in the R&D, pilot or small-scale demonstration phase are expected to be commercialized in the medium term. Wijffels and Barbosa [35] expect that commercial production of algal biofuels and protein-based co-products (chemicals, food, feed ingredients) will be economically feasible in 10–15 years. Given the variety of conversion technologies, and the dependence on feedstock and location (determining the circumstances including prices), process configurations of biorefineries are expected to be less uniform compared to petroleum refineries.

Recently, several studies have been performed to assess the economic and environmental performance of different biorefinery concepts. The BIOREF-INTEG project [112] compares the calculated cost of the main product of 8 reference cases in six biomass processing sectors (e.g. food, feed, biofuels) to 12 related biorefinery configurations. They find that for 9 out of 12 biorefinery concepts, the main product cost declines compared to the reference cost level. For example, a high cost reduction of 41% is found for bioethanol production when combined with the production of lactic acid. In general, biorefinery projects that have best prospects to improve the economics of the reference cases are found to be projects that (1) need no or little changes to the reference process, (2) aim at a better valorization of co-products (e.g. ECH production from glycerol), and/or 3) apply a fermentation process [112]. Laser et al. [113] compare the efficiency and environmental and economic performance of fourteen mature biorefinery configurations that include biochemical and thermochemical processes to produce fuels, power and/or animal feed protein from lignocellulosic biomass. They find that scenarios which integrate bio- and thermochemical processing (i.e. the feedstock is first biochemically converted to ethanol, and the lignin-rich residue is converted thermochemically) can achieve overall process efficiencies

of 70–80%, compared to 61–73% for biochemical biofuel production combined with power and/or protein production and 55–64% for thermochemical biofuel production combined with power generation [113]. With regard to process economics, configurations that involve biochemical production of ethanol are found to be most profitable (i.e. lowest levelized production costs, highest internal rate of return, and lowest minimum selling price compared to other configurations). While protein coproduction configurations especially have a good economic potential at crude oil prices below 50 $/bbl, biorefineries that integrate bio- and thermochemical processing become most profitable at higher oil prices [113]. Also, when a large share of the grid power is generated from coal, configurations that include power co-generation avoid most GHG emissions. When a future electricity system becomes less dependent on fossil fuels, however, the amount of avoided GHG emissions is the largest for biorefineries that integrate bio- and thermochemical processing [113].

4. Cost and emission data

In this section, we present the cost and GHG emission data gathered for biomass production, feedstock pretreatment, transportation and conversion, based on review of state-of-the-art-literature. For the purpose of completeness, we complement the cost data of conversion technologies for bio-based heat, power and fuel as compiled by the IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation [27] with cost and GHG emission data from other sources for bioenergy conversion technologies and fossil reference technologies, for bio-based materials and their fossil reference products, and for feedstock supply (production, transport and pretreatment).

4.1. Feedstock yields

Typical yields and projected yield improvements are summarized in Table 2 (sugar, starch and oil crops) and Table 3 (lignocellulosic biomass and MSW). Large differences in yields exist between crop types. For example, sugarcane production attains significantly higher yields compared to other conventional crops [114]. Among oil crops, oil palm attains the highest yields. With regard to algal oil, the potential yield is reported to be 40–50 thousand liter/(ha yr), resulting in a neutral lipid yield that is several times higher than the palm oil yield [2,115]. For each crop type, yields vary widely according to local climatic conditions, land suitability, and management levels (e.g. irrigation, fertilizer and pesticide use) [116]. Conventional cropping systems in Western Europe and other developed countries are already highly-input intensive and have attained considerable yield growth in the past 50 years [117]. In these regions, future productivity increases will be limited. Through the adaptation of advanced management practices, considerable gains in productivity could also be attained in other regions, particularly Sub-Saharan Africa, Latin America, Eastern Europe and Central Asia. Under the condition that current yield trends are maintained, Jaggard et al. [118] expect that global yields of agricultural crops will increase by a factor 0.9–2.4 between 2007 and 2050. This is equal to yield improvement rates of −0.2 to 2.1%/yr depending on the crop type and cultivation region. Average yield growth rates for crops considered in Table 2 range between 0.5%/yr for sugarcane and 1.3%/yr for sugar beet. The FAO expects an average agricultural production growth of 1.5%/yr for the next three decades [119]. Kindred et al. [120] project that yield growth rates can be increased to about 2%/yr under the most favorable conditions (e.g. high crop prices and high investments in agricultural research). Current yields of short rotation crops and perennial grasses are often similar or higher compared to yields of conventional crops, especially of starch and oil crops. In addition, yield projections show that lignocellulosic crops have potential for major yield improvements, in

both relative and absolute terms [39,116]. In Europe, Ericsson et al. [121] expect improvement rates from 1.5%/yr for poplar and eucalyptus, up to 3.2%/yr for miscanthus between 2005 and 2020.

4.2. Feedstock production costs

The production or roadside costs (Table 2 and 3) refer to total costs to make the feedstock available at the roadside for transportation and storage. Roadside costs depend on yields, the costs of land and labor, prices of inputs, and on the management system (e.g. use of machinery) [121]. For oil crops that have a relatively low yield, i.e. rapeseed, sunflower and soy, the roadside costs are 5.3–16 $/GJ$_{oil}$. This is rather high compared to 3–6 $/GJ$_{oil}$ for oil palm and 1.6–4.4 $/GJ$_{oil}$ for Jatropha, which can attain higher yields [2,122,123]. Low roadside costs are also found for high yield sugarcane (2.5–7.5 $/GJ) and lignocellulosic crops (0.7–8.7 $/GJ) [18,121–127]. In the roadside costs of agricultural and forestry residues, only collection and field transport are included. There are no costs related to production, because these residues are considered a residual stream from crop or wood production. As a result, roadside costs in Europe can be as low as 1 $/GJ [123,128].

Future roadside cost projections depend on assumed improvements in the production system (e.g. improved fertilization) and expected market developments (e.g. growing demand for biomass resources may result in higher land prices). Cost projections by Ericsson et al. [121] suggest that the potential for cost reductions in Europe is smaller for starch and sugar crops than for SRC and perennials. Also, cost-supply curves by De Wit and Faaij [123] project that the major share of the European production of oil, starch and sugar crops in 2030 can be accomplished at a cost of 5–12 $/GJ. Cost projections for SRC and perennials in the same year and region range between 2 and 7 $/GJ [123]. With regard to potential future algae lipid production, medium-term costs are estimated to be 30–80 $/GJ for open pond reactors and 50–140 $/GJ for PBRs [28].

4.3. Pre-treatment and transportation costs

The costs of delivering biomass to the conversion plant are the total costs of feedstock production, pretreatment and transportation. The delivering costs are thus determined by spatial distribution of biomass resources, transport distance, mode of transport and the type of biomass pretreatment. Below, we discuss the costs of various pretreatment and transportation options.

4.3.1. Costs of pretreatment

For pelletization of wood residues like logs and sawdust, Uslu et al. [43] and Sikkema et al. [44] give costs between 1.7 and 5.4 $/GJ (excluding feedstock costs). Uslu et al. [43] find a pelletization cost of 1.3 $/GJ for energy crops. The pellet production costs are mainly defined by feedstock drying, pressing and cooling [44]. For torrefaction of wood chips, Uslu et al. [43] estimate the costs to be 3.9 $/GJ, and for the TOP process 3.0 $/GJ. Batidzirai et al. [48] find TOP costs of 4.1 $/GJ for small-scale, and 2.8 $/GJ for large-scale production. For pyrolysis, Uslu et al. estimate the costs to be 7.3–14.6 $/GJ for wood chips in Europe and 1.8–4.5 $/GJ for energy crops in Latin America [43].

4.3.2. Costs of logistics

Regional or national truck transport of raw biomass costs 0.3–1.6 $/GJ for sawdust and shavings [44], and 2.4 $/GJ for corn stover in the USA [28]. In Europe, national transportation costs for pellets range from 0.3 $/GJ delivered for inland river shipping to 1.2 $/GJ for small-volume truck transport. Train and large-volume truck transport costs about 0.8 $/GJ [37,44]. Costs for international

Table 2
Sugar, starch and oil crops: feedstock yields, projected yield improvement, current and projected roadside costs.

	Feedstock	Region	Present average yields (GJ/(ha.yr))[a]	Projected yield improvement (%/yr)	Roadside costs ($/GJ feed)[b]		References
					Current	2030	
Starch	Mixed	Europe			6.6–11.3	6–10	[123]
	Wheat	Europe	31–160	1.3			[114,118,121]
		USA	41–47	1.0			[114,118]
		Canada	36–45	1.0			[114,118]
		Argentina	27–44	1.1			[114,118]
	Corn	Europe	35–147	1.1			[114,118]
		USA	140–156	1.0	6.7		[19,114,118]
		Canada	126–136	0.8			[114,118]
		Argentina	84–115	1.4			[114,118]
		China	78–84	1.4			[114,118]
	Triticale (whole crop)	Europe	144–216	0.3			[121]
	Cassava	China	97–103				[114]
		Africa	10–74				[114]
		Africa, semi-arid	14–56		10 – > 50		[125]
		Africa, arid	1–28		15 – > 50		[125]
Sugar crops	Sugarcane	Brazil	355–415	1.0	2.5		[18,114,118,129]
		USA	375–425	0.1			[114,118]
		Mexico	365–405				[114]
		C. America	390–410				[114]
		Colombia	490–530				[114]
		Argentina	440–445	0.8			[114,118]
		India	340–360	0.9			[114,118]
		Australia	420–465	0.4			[114,118]
		Mozambique	350–522		7.5		[122]
	Sugar beet	Europe	82–232	1.0	5.3–10	5.3–9.3	[118,123,130]
	Sorghum (whole crop)	Europe	23–180	0.3–1.1			[114,118,121]
Oil crops	Rapeseed	Europe	30–70	1.0	7.2–16		[2,114,118]
	Sunflower	Europe	20–44	0.6			[114,118]
	Rape/sunflower	Europe			5.3–13.3	8–12	[123]
	Soy	Brazil	18–21	1.2			[2,118]
		Argentina	19–30	1.2	22.7		[118,122]
		North America	16–19	0.6–0.9	11.7		[2,118]
	Palm	Brazil	170				[2]
		Colombia	165				[122]
		Asia (Indonesia/Malaysia)	110–180		3–6		[39,122,131]
		C./W. Africa	27				[39]
	Jatropha	World	17–88		3.2		[2]
		Tanzania	17–46		1.6–4.4		[122]
		Africa, semi-arid	36–48		26– > 40		[125]
		Africa, arid	3–37		29– > 50		[125]

Roadside costs: total costs to make the feedstock available at the roadside for transportation and storage.
Conversion factors used to convert yield data to GJ/(ha.yr) can be found in the supplementary material.

[a] For oil crops: GJ oil/(ha yr).
[b] for oil crops: $/GJ oil.

transport of pellets range from 1.1 $/GJ for truck transport to 1.7 $/GJ for short sea shipping. Intercontinental ocean shipping of pellets from Canada to Western Europe (16,500 km) costs 1.8–4.8 $/GJ [37,44], and from Latin America to Western Europe (11,500 km) about 1.0 $/GJ [43]. For torrefied pellets and pyrolysis oil, Uslu et al. [43] estimate the costs of ocean shipping to be 1.6 $/GJ and 1.8 $/GJ, respectively. They also show that ocean shipping is more expensive for torrefied biomass (55 $/tonne dry) compared to torrefied pellets (37 $/tonne dry) [43].

4.4. Biomass conversion costs

Below, we discuss the cost data found for biomass conversion to bioenergy and biomaterials. Important factors that determine the biomass conversion costs are: scale of conversion, load factors, and the production volume and value of co-products.

4.4.1. Heat

We give an overview of present and projected cost data for domestic and district heat production from biomass and fossil resources in Table 4. Comparison of bioenergy data from the International Energy Agency (IEA) [57] and the European Environment Agency (EEA) [54] to the fossil reference shows that the investment and operation & maintenance (O&M) costs are significantly higher for all biomass systems. This is also true for 2030, as the projected reductions in investment and O&M costs are limited for both domestic and district heating. For domestic chip and pellet systems the reduction in investment costs is 0–7% [54,57]. The reductions for district heat systems are projected to be about 10% for a 5 MW boiler, and 5–6% for a 0.5 MW boiler and the 150 kW gasifier option [54]. Yet, the data from the IEA and EEA show that economies of scale have a significant effect on both investment and O&M costs. Although this is especially true for domestic heating, the possibilities for upscaling of domestic heating systems are limited. A study by Weiss et al. [138],

Table 3
Lignocellulosic biomass and MSW: feedstock yields, projected yield improvement, current and projected roadside costs.

	Feedstock	Region	Average yields (GJ/(ha yr))		Projected yield improvement (%/yr)	Roadside costs ($/GJ feed)		References
			Present	Projected		Current	Projected	
SRC	Mixed	World					< 2.3–4.5 (2050)	[132]
		Europe		355–710 (2050)		2.7–6.2	2–5.3 (2030)	[116,121,123]
		USA					< 2.5–3.1 (2030)	
		Africa, semi-arid	110–250	315–475 (2050)[a]		1.9–4.2		[116,125]
		Africa, arid	14–175			2.2–23.8		[125]
		Northern America		375–535 (2050)				[116]
		Latin America		315–455 (2050)				[116]
	Willow	World	190	290 (2030)				[39]
		USA	210–230			2.5		[127]
		Europe	90–250		2.3	1.8–4.7		[121,124,130,133]
	Poplar	World	180	265 (2030)				[39]
		Europe	180–375		1.5	1.8–4.7		[121,124,133]
		USA	110	385–545 (2050)				[116,134]
	Eucalyptus	USA	245					[116,134]
		Latin America	340–435			1.3		[43,124,133]
		Europe	230		1.5			[121]
		Mozambique	136–485			0.7–1.4		[126]
Perennial grasses	Mixed	Europe				4–8.7	3.3–8 (2030)	[121,123]
		USA					< 2.1–3.3 (2030)	[135]
	Miscanthus	World	190	380 (2030)				[39]
		Europe	17–340		3.2			[121,130]
	Switchgrass	World	215	290 (2030)				[39]
		S. Europe	235		2.3			[121]
		USA	235					[116,134]
		Argentina	90–180					[116,136]
	Reed Canary Grass	Europe	140		2.3			[121]
Fuel wood	Forest wood	World	6					[116]
	Forest wood+res.	World	12–69		0.8–1.3			[137]
				14–86 (2030)				
				16–106 (2050)				
	Forest residues	Europe	2–22			0.7–5.3	1–4 (2030)	[2,123,124,128]
		USA				< 2–3		[135]
Residues	Agric. residues	Europe	5–125			1–5.3		[123,128]
		USA				< 2.2–2.8		[135]
		World	7–31	9–35 (2030)				[137]
				11–38 (2050)				
	Straw	USA	65			< 2.2–3.3		[134,135]
	Wheat straw	Europe	60					[2]
		USA	7–75			< 2.2–3.3		[2,135]
	Sugarcane straw	Brazil	90–126					[2]
	Corn stover	N. America	15–155			< 2.2–3.3		[2,135]
		India	22–30					[2]
	Sorghum stover	World	85					[2]

Roadside costs: total costs to make the feedstock available at the roadside for transportation and storage.
Conversion factors used to convert yield data to GJ/(ha yr) can be found in the supplementary material.

[a] Projection for Sub-Saharan Africa.

however, suggests that cost reductions can be attained in the production of the boiler systems. They find that, amongst others, economies of scale in both boiler assembly and component manufacturing played an important role in cost reductions of fossil-based condensing gas boilers. Unlike the cost components, the feedstock conversion efficiencies of biomass heating systems are comparable to the fossil reference systems. By 2030, technological improvements in biomass conversion will result in efficiency increases of 2–4%.

4.4.2. Power

Cost data for power generation from biomass and fossil fuels are provided in Table 5 (power generation in non-CHP plants) and Table 6 (power production through CHP). The typical capacities in biomass systems are generally lower compared to fossil reference systems. As a result, mainly because of economies of scale, the specific investment costs ($/kW$_e$) are higher. In both tables, the costs for cofiring only cover retrofit costs to make an existing coal power plant suitable for biomass cofiring. As a result, cofiring

options have substantially lower investment costs than dedicated biomass systems. Direct cofiring is a commercial technology, and has lower investment costs compared to parallel and indirect cofiring. Projections, however, do not show cost reductions for direct cofiring [[55] in:[27];[54]]. The projected reduction in the investment costs of indirect cofiring is 13% [54].

For both dedicated biomass combustion and gasification technologies (both power and CHP production), we find large divergence in investment costs between literature sources. Regarding combustion, this may be explained by a difference in costs between established and advanced technologies. In the case of gasification, the variance can partially be explained by differences between specific gasification technologies [7,8,142], but a comparison between Obernberger et al. [8] and EEA [54] shows that estimates of further investments do also vary. Considering the lower investment levels for gasification, we find that a present 50 MW$_e$ IGCC may have lower specific investment costs than a 100 MW$_e$ combustion-based steam cycle [[55] in:[27]; [54]]. Yet, at the higher level the (scaled) investment costs are lower for dedicated biomass combustion. In addition, gasification combined

Table 4
Present and projected cost data for heat production from biomass and fossil resources[a].

		Typical size of devise (MW$_{th}$)	Investment cost ($/kW$_{th}$)	O&M fixed annual ($/(kW$_{th}$.yr))	Feedstock conversion efficiency heat (%)	Capacity factor (%)	Economic design lifetime (years)	References
Biomass present								
Domestic	Boiler	0.005–0.1	310–1200	13–43	80–88	13–29	10–20	[57]
		0.01–0.05	564–951	19–29	79–82	18	15	[54]
District	Boiler	0.5–5	532–783	24–147	79–83	46	15–20	[54]
	Gasifier	0.15	874	82	83	37	15	[54]
Biomass projection 2030								
Domestic	Boiler	0.01–0.05	523–899	19–29	83–85	18	15	[54]
		0.005–0.1	310–1200	13–43	88–95	13–29	12–24	[57]
District	Boiler	0.5–5	476–740	21–145	83–86	46	15–20	[54]
	Gasifier	0.15	821	80	87	37	15	[54]
Fossil reference present[b]								
Domestic	NG boiler	0.008–0.04	41–675	2–17	88	29	10	[139–141]
District	Oil boiler	50	132	9[c]	90	68	30	[139]

NG: natural gas.

[a] If a range in size of the system is given, the higher cost data and the lower conversion efficiency, capacity factor and lifetime refer to small-scale production and vice versa.

[b] No cost projections for 2030 were found in the literature. We assume investment costs decline with 5% from current to 2030, based on rate found for biomass systems.

[c] O&M fixed annual 2 $/(kW$_{th}$.yr)+O&M non-feed variable 1 $/MWh$_{th}$.

Table 5
Present and projected cost data for power generation from biomass and fossil fuels (power only, CHP not included)[a].

	Typical size of devise(MW$_e$)	Investment cost ($2005/kW$_e$)	O&M fixed annual ($2005/ (kW$_e$.yr))	Non-feed variable operating cost (c/kWh_e$)	Feedstock conversion efficiency electricity (%)	Capacity factor (%)	Econ. life-time (yrs)	References
Biomass present								
Dedicated combustion/Gasification								
SC (fixed/ fluidized bed)	25–100	2600–4100	84–87	0.34–0.4	27–28	70–80	20	[[55] in: [27]]
SC	25–100	1850–2800						[6,144][e]
IGCC	50	1900–3500	88–99		45	68–80	20	[54,62][b,e]
	250	1200–2200	55–61		45	68–80	20	
Cofire								
Direct	20–100	430–500	12	0.18	36	70–80	20	[[55] in: [27]]
	35–70	186	118		41	68	30	[54]
Parallel	20–100	760–900	18		36	70–80	20	[[58] in: [27]]
Indirect (CC)	450	901–1037	46–51		44	68	20	[54][b]
Biomass projection 2030								
Gasification								
IGCC	50	1600–3000	94–104		45	68	20	[54,62][b,d]
	250	1000–1900	58–64		45	68	20	
Cofire								
Direct	35–70	186	118		47	68	30	[54]
Indirect (CC)	450	798–919	40–45		47	68	20	[54][b]
Fossil reference								
Present								
NGCC	150–870	472–1133	24–45[c]	0–0.02	38–60	85	30	[143,145]
Coal	300–1300	732–2505	26–60[c]		39–46	85	40	[145]
PC	n.a	2060	75	0.36	46	85	30	[143]
2030								
NGCC	n.a	784	21	0.02	58	89	30	[143]
PC	n.a	1867	64	0.33	46	89	30	[143]

SC: steam cycle; IGCC: integrated gasification combined cycle; CC: combined cycle; NGCC: natural gas combined cycle; PC: pulverized coal; n.a. not available.

[a] If a range in size of the system is given, the higher cost data and the lower conversion efficiency, capacity factor and lifetime refer to small-scale production and vice versa.

[b] For gasification routes from EEA [54], only costs of electricity production were given (taking gasified biomass as feedstock). For comparison reasons, gasification costs were added based on Bain [7] and Obernberger et al. [8] (see supplementary material). For 300 MW output (clean product gas) the current investment cost is estimated to be 80–110 M$. In the longer term, the investment costs are assumed to reduce with 10% to 72–99 M$. Current gasifier efficiency is estimated to be 80%. The projected gasifier efficiency is 85%. The scaling factor is 0.7 and O&M costs are 4% of investment costs.

[c] Fossil references from IEA [145]: O&M costs include both variable and fixed costs.

[d] Based on the cost projection of EEA [54], a cost reduction of about 14% was applied to current investment cost levels.

[e] Investment costs given for another size were scaled using a scaling factor $n=0.7$.

with a gas engine attains lower investment costs compared to an IGCC at similar scales [54].

Of small-scale CHP technologies, Stirling engines have the lowest investment costs [54]. For commercial CHP production through MSW combustion, investment costs are very high compared to all other biomass technologies. Also, projections for 2030 do not show any cost reductions [54]. Projected reductions in investment costs of other power and CHP technologies range from 11% for indirect cofiring, and 12–19% for gasification-based technologies to 24% for a Stirling engine [54]. For larger-scale dedicated biomass combustion technologies (> 2 MW$_e$), no projections were found. The investment costs of natural gas and coal-based power plants are projected to decrease by about 10% until 2030 [143]. In contrast, the investment costs of natural gas-based CHP technologies are projected to increase by 5–6%. Yet, while the electric efficiency of NGCC-based CHP production is projected to increase by more than 30%, the feedstock conversion efficiencies of other fossil reference technologies are not projected to improve [143]. The efficiencies of bioenergy technologies are expected to increase by 1–7% for large-scale gasification (IGCC and indirect cofire) and 17–25% for small-scale CHP [[55] in:[27];[8,27,54,57]].

4.4.3. Fuels

In Table 7, we provide an overview of cost data for the production of first- and second-generation biofuels. As no appropriate data on investment and O&M costs of an oil refinery for gasoline and diesel production is available, we cannot compare cost data for biofuels and fossil fuels. Therefore, only final production cost data will be compared in Section 5.1.1.

Currently, the highest production capacity is attained for sugarcane ethanol. Scaling suggests that the investment costs for corn and wheat ethanol production at this capacity level (1000 MW feed) would be just above the costs for sugarcane (about 120–135 $/kW$_{feed}$). This is true for data from Bain [7] for wheat ethanol production in Canada, Argentina and the USA. For Europe, much higher investment costs are found by the EEA [54]. For combined ethanol and sugar production, which is often the case in Brazil, only approximately half of the feedstock is used for ethanol production. As a result, the feedstock conversion efficiency is only 17%. When only taking into account the feedstock share for ethanol, the efficiency is 38–42% [64,144]. Biodiesel production from soy and palm oil attains a very high feedstock conversion efficiency of 103%, because methanol is incorporated into the product. The same is true for renewable diesel production (hydrogen added), which attains a conversion efficiency of 95% [7]. In addition, at relatively low capacity, the hydrogenation route results in the lowest investment costs of all biofuels (hydrogen production excluded; hydrogen input is included in variable O&M costs). If investments costs for methanol or hydrogen production respectively would be included, investments would be considerably higher. At capacities between 300 and 700 MW$_{feed}$, the production of second-generation fuels requires very high investment costs [7,28,60]. The investments are projected to decline, partly as a result of upscaling, but remain higher than first-generation investment costs [7,28,60]. This is especially the case for FT diesel. During the production of second-generation fuels, however, often more power is co-generated than needed for the process [7,28,54,60]. By-product revenues for exported electricity will have a positive effect on the production costs. It is expected that improved technology for sugarcane ethanol production will also result in increasing sale of electricity [147].

4.4.4. Materials

Table 8 shows the cost data for current olefins production from Ren et al. [14]. In their study, Ren et al. [14] also made cost projections for these production routes. However, the study does not provide sufficient data to reproduce future levelized cost data. Cost figures for biotechnological conversion routes from sugarcane and corn to ethylene and other white biotechnology chemicals are derived from Hermann and Patel [15].[5] In Hermann and Patel, the costs are based on the conversion of fermentable sugar to materials (i.e. the conversion costs do not depend on the type of feedstock and the required process steps, but on the price of fermentable sugar). We have recently updated these calculations[6,7] (see Saygin et al. [4] for more details) and will present the results in Section 5.2. We did not find production cost data of other materials (amongst which are starch plastics, cellulose polymers, ECH and epoxy resin). The figures from Ren et al. [14] show that the cost figures vary with the specific process design. When electricity is co-generated, the investment and O&M costs are generally higher, and feedstock conversion efficiencies are lower. The investment costs are the lowest for biomass gasification combined with the methanol-to-olefins process. Gasification combined with the FT naphtha process results in the highest investment costs. Regarding the production routes of ethylene through biomass fermentation, the investment and fixed O&M costs are the highest for the conversion of lignocellulosic biomass. This is because more complex technology is required for hydrolysis and fermentation. When production scales would be increased, fermentation-based processes become modular beyond a certain size, while cost reductions may still be attained for gasification processes.

Current and projected conversion efficiencies for various biochemicals are compared in Table 9. The efficiencies are the highest for starch feedstock (corn) and the lowest for sugar feedstock (sugarcane). This is consistent with Ren et al. [14]. The efficiencies for PTT are higher than for other products, because the feedstock for PTT only partially consists of biomass.

4.4.5. Technological learning

Typically, the increasing diffusion of a technology into the market results in a decrease of the unit cost of the technology [20]. This can be explained by mechanisms like learning-by-doing, technological innovation, and economies of scale. The combined effect of these mechanisms is referred to as technological learning [138]. Empirical observations show that costs tend to decline at an almost fixed rate with each doubling of the cumulative production [20]. This rate is called the learning rate, and the relationship between unit cost and cumulative production can be described by the so-called experience (or learning) curve.

4.4.5.1. Historic learning in biobased systems.
In recent literature, a number of analyses have been performed to quantify learning in

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[5] Published as production costs plus profit (PCPP).

[6] The work of Hermann and Patel was conducted within the BREW project (2003–2006), for which confidential data was made available. The confidential data were not used in our update. Wherever the original calculations involved the use of confidential data, extrapolation and triangulation was applied using public data for various crude oil prices published in Patel et al. [93], Hermann and Patel [15] and Hermann et al. [150].

[7] To estimate the production costs, we assumed that the production costs are 5–25% below the product value (PCPP). This was based on investment and production cost data for bio-ethylene published by IEA-ETSAP [95]: the capital costs of bio-ethylene plants are stated to be 278 M$ at 200 kt/yr and 400 M$ at 350 kt/yr. At a capital charge of 11% (CRF, depreciation only), this means that the investment costs are 125–155 $/tonne. The report gives production costs of 970–1630 $/tonne (Brazilian sugarcane) and 1700–2730 $/tonne (US corn). At a capital charge of 30% (depreciation plus profits), the investment costs would be 340–420 $/t and the production costs would increase to 1185–1895 $/tonne (sugarcane) and 1915–1995 $/tonne (corn). So, to come back to the production costs we would need to reduce the product value by 7–21%. This is consistent with the sensitivity analysis for the capital charge in Hermann and Patel [15].

Table 6
Present and projected cost data for power generation by CHP[a].

	Typical size of devise (MWe)	Investment cost ($/kWe)	O&M fixed annual ($/(kWe.yr))	O&M non-feed var. ($c/kWhe)	Feedstock conversion efficiency electricity (%)	Power-heat ratio	Capacity factor (%)	Econ. life-time (yrs)	References
Biomass present									
Combustion									
SC (fixed bed)	25–100	2800–4200	86	0.35	24	0.67	70–80	20	[[55] in:[27]]
SC	2.5–10	4100–6200	54	3.5	18	0.28	55–68	20	[8,27]
SC	2.5–10	2500–4000							[146]
Direct cofiring (SC)	5–100	184–249	113–153		26	0.48	68	25	[54]h
Steam engine	0.8	4830–5587	563–586		12–13	0.19 –0.21	68	20	[54]
ORC	0.65–1.6	6500–9800	59–80	5.1	14	0.19	55–68	20	[8,27]
	0.8	5806–6710	513–542		9–12	0.14 –0.19	68	20	[54]
Stirling engine	0.05	6086	205		16	0.27	68	10	[54]
MSW (SC)	10	11,125	671		14	0.4	80	15	[54]
AD – gas engine	0.3–3.36	2487–5098	554–702		13–19	0.67	68–91	15–25	Derived from IEA [57]
Gasification									
Gas engine	0.1	9000–15,000	494	582	30	0.71	68	20	[8,54,61]b,f
	1	4500–7500	245–291		28–34	0.82	68	20	
	10	2400 3700	65	1.1–1.9	30	1.52	68	20	
IGCC	50	2000–3500	96–107		40	0.88	68–80	20	[54,61]b,f
	250	1200–2300	59–66		40	0.88	68–80	20	
Micro gas turbine	0.1	6676–8835	460–574		31	0.65	68	15c	[54]b
Biomass projection 2030									
Combustion									
Steam engine	0.8	3941–4728	535–561		15–16	0.24 –0.26	68	20	[54]
ORC	0.8	4889–5660	486–510		14	0.22	68	20	
Stirling engine	0.05	4541	159		20	0.34	68	10	[54]
Direct cofiring (SC)	5–100	184–249	113	153	28–30	0.56	68	25	[54]h
MSW (SC)	10	11,125	671		17	0.40	80	15	[54]
Gasification									
Gas engine	0.1	8000–13,000	456	530	35–	0.88	68	20	[8,54,61]b,e
	1	3900–6600	211–246		40	1	68	20	
	10	2000–3200	65	1.1–1.9	40	1.52	68	20	
IGCC	50	1700–3000	96	106	42	1	68–80	20	[54,61]b,g
	250	1000–2.000	59–66		42	1	68–80	20	
Micro gas turbine	0.1	5434–7193	410	481	38	0.87	68	15	[54]b
Fossil reference									
Present									
NGCC	< 250	930	48		32		66	30	[143]
Gas turbine	25	1262	48		32		64	30	[143]
Gas engine	< 2	709	38		41		46	30	[143]
NGGT	60–405	715–1683	30d–104		38		85	30	[143]
2030									
NGCC	< 250	1341	59		43		67	30	[143]
Gas turbine	8–45	1252–1895	45–93		25–28		75	30	[143]
Gas engine	< 2	745	35		41		46	30	[143]

SC: steam cycle; CC: combined cycle, ORC: Organic Rankine Cycle; IGCC: integrated gasification combined cycle; NGCC: natural gas combined cycle; NGGT, natural gas gas turbine.

[a] If a range in size of the system is given, the higher cost data and the lower conversion efficiency, capacity factor and lifetime refer to small-scale production and vice versa.

[b] For gasification routes from EEA [54], only costs of electricity production were given (taking gasified biomass as feedstock). For comparison reasons, gasification costs were added based on Bain [7] and Obernberger et al. [8] (see supplementary material). For 300 MW output (clean product gas) the current investment cost is estimated to be 80–110 M$. In the longer term, the investment costs are assumed to reduce with 10% to 72–99 M$. Current gasifier efficiency is estimated to be 80%. The projected gasifier efficiency is 85%. The scaling factor is 0.7 and O&M costs are 4% of investment costs. Note that this approach leads to high investment and fixed O&M costs for small-scale gasification routes (0.1–1 MWe), in EEA the 'feedstock' costs were not significantly higher compared to larger-scale units.

[c] In EEA [54] an economic lifetime of 10 years was found, in this work 15 years is used to account for the gasifier lifetime.

[d] Fossil references from IEA [145]: O&M costs include both variable and fixed costs.

[e] Based on the cost projection of EEA [54], a cost reduction of about 12% was applied to current investment cost levels.

[f] Investment costs given for other sizes were scaled using a scaling factor $n=0.7$.

[g] Based on the cost projection of EEA [54], a cost reduction of about 15% was applied to current investment cost levels.

[h] Investment costs given for another size were scaled using a scaling factor $n=0.9$.

Table 7
Present and projected cost data for first- and second-generation biofuel production[a].

	Typical size of devise (MW[feed])	Investment cost ($2005/kW[feed])	O&M fixed annual ($2005/(kW[feed].yr))	O&M non-feed variable ($/GJ[feed])	Feedstock conversion efficiency fuel (%)	Capacity factor (%)	Economic lifetime (years)	References
Current								
Ethanol – 1st generation								
Sugarcane[b]	172	259–358	25–35	0.87	17	50	20	[[7,27]; [64,144,148] in:[2]]
	1024	83–115	16–22	0.87	17	50	20	
Corn[h]	138	241–310	17–27	1.98	54	95	20	[[7,27]; [64] in:[2]]
	554	158–203	9–13	1.98	62	95	20	
Wheat	152	220–282	16–25	1.41	49	95	20	[[7,27]; [6,149] in:[2]]
	166–498	419–552	22–28		54	86	15	[54][c]
	607	144–185	8–12	1.41	53	95	20	[[7,27]; [6,149] in:[2]]
Diesel – 1st generation[d]								
Biodiesel soy oil	44	301–323	27–46	2.58	103	95	20	[7,27]
	440	159–171	9–13	2.58	103	95	20	
Biodiesel palm oil	44	299–339	34–46	2.58	103	95	20	[7,27]
	440	158–180	10–13	2.58	103	95	20	
Biodiesel rapeseed	102–401	142–167	30–35		49	91	20	[54][e]
Renewable diesel soy oil	117–235	49–67	2–3	2.29	92	95	20	[7]
BC fuels – 2nd generation								
Ethanol SHF	440	497	19	3.09	37[g]	96	20	[28]
Ethanol SSF	400–	528–683	34–44		35	91	20	[60][f]
Ethanol SSCF	334	562	37	1.11	44	95	20	[7]
	667	470	27	2.11	44	95	20	
TC fuels – 2nd generation								
Ethanol	440	550	32	0.69	32[g]	96	20	[28]
	374–747	420–510	25–33	0.17	40	95	20	[7]
Methanol	400–2000	394–552	16–22	0.47	59	91	20	[60][f]
Hydrogen	400–2000	427–580	17–23		35	91	20	[60][f]
FT diesel	400–2000	539–686	24–30		42	91	20	[60][f]
Projection 2030								
1st generation								
Biodiesel rapeseed	80–401	167–181	35–38		62	91	20	[54][e]
Ethanol wheat	179–490	362–436	19–23		54	86	15	[54][c]
BC fuels – 2nd generation								
Ethanol	179	243	101		56	86	15	[54]
Ethanol CBP	400–2000	383–512	14–18		47	91	20	[60][f]
TC fuels – 2nd generation								
Methanol	400–2000	341–442	14–18		57	91	20	[60][f]
Hydrogen	400–2000	388–486	16–19	0.01	41	91	20	[60][f]
FT diesel	400–2000	434–552	19–24		42	91	20	[60][f]
	1075	925	56		47	86	20	[54]

BC, biochemical; TC, thermochemical.

[a] If a range in size of the system is given, the higher cost data and the lower conversion efficiency, capacity factor and lifetime refer to small-scale production and vice versa.

[b] Integrated sugar mill: 50% ethanol & 50% sugar production (sugar is considered to be a by-product.)

[c] Cost data from EEA [54] for large-scale (289 MW ethanol) derived using a scaling factor of 0.75 [60].

[d] Feedstock conversion efficiency is given for vegetable oil to diesel, except for rapeseed biodiesel where the efficiency is given for rapeseed to biodiesel; methanol or hydrogen inputs are included in O&M costs.

[e] Original capacity 12.5 MW biodiesel, scaled to 50 and 250 MW biodiesel; cost data derived using a scaling factor of 0.95 [60].

[f] Scaling was used to derive cost data for larger scale (present cost data) or smaller scale (projected cost data). For scaling factors, see Hamelinck and Faaij [60].

[g] Derived from production capacity and feedstock use, assuming HHV ethanol is 23.4 MJ/liter and HHV lignocellulosic biomass is 18 GJ/t dm.

[h] Dry milling.

bioenergy systems, see Table 10. Attempts to carry out the same for biomaterials have not been successful. The major reasons are the lack of time series for prices due to the early stage of development and the non-existence of a bulk market price (due to the small production quantities).

The learning system of bioenergy systems can be split into three separate parts, i.e. the feedstock supply system, O&M of the conversion plant, and investment in the plant. Cost reductions in feedstock production are assessed for various crop types [18,19,133,151]. In all cases, the development of improved plant varieties (increased yields)

Table 8
Present cost data for olefin production [107].

		Investment cost ($/t product)	O&M ($/t product)	Non-feed variable operating cost ($/t product)	Power co-generation (GJ/t product)	Feedstock conversion efficiency olefin (wt%)	Capacity factor (%)	Economic lifetime
Fermentation-ethylene ETE	Sugarcane	275	38.8	0	16	11.6	91	15
	Corn	275	38.8	816	0	28.1	91	15
	Ligno	251	83.4	176	4	18.9	91	15
		353	213.6	0	22	15.3	91	15
		353	213.6	88	5	16.5	91	15
Gasification-Olefins[a]	FT	395	122.5	0	16	9.0	91	15
	naphtha	462	140.6	0	50	10.5	91	15
	MTO	221	84.8	309	0	21.1	91	15

[a] Mainly ethylene and propylene.

Table 9
Current and projected conversion efficiencies for fermentative biochemicals and biomaterials, derived from [11].

		Conversion efficiency (t product/t dm feed)[a]		
		Sugarcane	Corn	Corn stover
Ethanol	Current	0.16	0.44	
	Future	0.17	0.45	0.25
Butanol	Current	0.12	0.32	
(ABE[b])	Future	0.14	0.38	0.21
Ethylene	Current	0.10	0.26	
	Future	0.10	0.27	0.16
PLA	Current	0.17	0.68	
	Future	0.26	0.68	0.40
PHA	Current	0.11	0.31	
	Future	0.14	0.40	0.21
PTT	Current	0.39	1.02[c]	
	Future	0.51	1.36[c]	0.70

[a] Values based on sugar contents: sugarcane 0.42 t sucrose/t dm [147,166]; corn 0.94 t sucrose/t dm; corn stover 0.56 t sucrose/t dm [11]; future values represent the technical potential after 20–30 years of R&D [11].
[b] Butanol is produced through ABE fermentation, by which acetone and ethanol are also produced.
[c] The biomass feedstock conversion efficiencies for corn-based PTT are higher than 1 because the feedstock for PTT is only partially bio-based.

Table 10
Learning rates for major components of bioenergy systems and final energy carriers.

	LR (%)	Time frame	Region	N	R^2	References
Feedstock production						
Sugarcane (tonnes sugarcane)	32 ± 1	1975–2005	Brazil	2.9	0.81	[18]
Corn (tonnes corn)	45 ± 1.5	1975–2005	USA	1.6	0.87	[19]
Rapeseed (tonnes rapeseed)	20 ± 1	1971-2006	Germany		0.97	[151]
Eucalyptus (EJ eucalyptus)	37	1955-2010	Brazil			[133]
	27		World			
Poplar (EJ poplar)	22-29		Italy			[133]
Logistic chains						
Forest wood chips (Sweden)	12–15	1975–2003	Sweden/ Finland	9	0.87–0.93	[152]
Investment and O&M costs						
CHP plants	19–25	1983–2002	Sweden	2.3	0.17–0.18	[20]
Biogas plants	12	1984–1998		6	0.69	[20]
Ethanol production from sugarcane	19 ± 0.5	1975–2003	Brazil	4.6	0.8	[18]
Ethanol production from corn (only O&M costs)	13 ± 0.15	1983–2005	USA	6.4	0.88	[19]
Final energy carriers						
Ethanol from sugarcane	7	1970–1985	Brazil			[153]
	29	1985–2002		~6.1	n.a.	
Ethanol from sugarcane	20 ± 0.5	1975–2003	Brazil	4.6	0.84	[18]
Ethanol from corn	18 ± 0.2	1983–2005	USA	7.2	0.96	[19]
Electricity from biomass CHP	8–9	1990–2002	Sweden	~9	0.85–0.88	[20]
Electricity from biomass	15	Unknown	OECD	n.a.	n.a.	[154]
Biogas	0–15	1984–2001	Denmark	~10	0.97	[20]

LR, Learning rate; N, number of doublings of cumulative production; R^2, coefficient of determination; n.a. not available.

was found to be an important driver for historic cost reductions. In addition, sugarcane production costs were significantly reduced by increasing the length of the ratoon system, and improving the management system (increased harvesting efficiency) [18]. In corn production, costs were highly influenced by the increased size of farms (economies of scale) [19]. The production costs of dedicated energy

Table 11
Cradle-to-grave GHG emissions of heat and power generation.

			Timeframe	Upstream (gCO$_2$-eq/MJ feed)		Life cycle (gCO$_2$-eq/MJ product)		Reference
				Min	Max	Min	Max	
Heat	Domestic	Wood pellets	EU present	1.4	4.7	4.3	11.6	[156]
			EU	8.8	10.3	10.4	12.1	[44]
			EU 2030	2.3	4.0	6.1	9.1	[156]
		Wood chips	EU present	2.0	2.0	6.0	9.4	[156]
			EU 2030	1.9	2.0	6.3	7.6	[156]
		SRC	EU present	5.9	7.0	11.0	14.5	[156]
			EU 2030	3.9	4.3	8.9	10.3	[156]
	District	Wood pellets	EU	2.5	2.6	2.7	2.8	[44]
		Lignocellulosic	EU present	4.8	7.0	8.5	13.7	[156]
		(SRC & perennials)	EU 2030	2.8	9.4	6.3	14.8	[156]
Power[c]	Cofire[b]	All feedstocks – power	1980–2010			−1	47	[155]
		Wood pellets (Canada to NL) – power	present	8.6	16	21.1	39.1	[44]
		Wood chips – power	EU present	2.0	2.0	11.8		[156]
		Wood chips – CHP	EU present	2.0	2.0	−113.7		[156]
	Combustion	All feedstocks – power	1980-2010			1	42	[155]
		Wood pellets Stirling – CHP	EU present	1.4	4.7	−274.3		[156]
		Wood chips ORC – CHP	EU present	2.0	2.0	−440.7		[156]
		Wood chips steam engine – CHP	EU present	2.0	2.0	−360.3		[156]
		Biogas – CHP (manure, landfill)	EU present	6.0	13.3	−67.6	−3.3	[156]
		Biogas – CHP (corn, wheat, sorghum)	EU present	15.1	36.5	−6.1	52.8	[156]
			EU 2030	11.5	23.4	−14.2	14.4	[156]
	Gasification[a]	All feedstocks – power	1980–2010			1	36[d]	[155]
		Wood chips IGCC – power	EU present	5.4	10.6	58.9		[156]
		Wood chips IGCC – CHP	EU present	5.4	10.6	−25.6		[156]
		Wood chips indirect cofiring – power	EU present	5.4	10.6	60.1		[156]
		Wood chips gasification ICE/GT – CHP	EU present	5.4	10.6	−74.3	−52.4	[156]
		SRC gasification ICE – CHP	EU present	10.7	16.0	−68.3	−59.4	[156]
			EU 2030	9.2	11.2	−68.8	−63.9	[156]

SC, steam cycle; ORC, Organic Rankine Cycle; ICE, internal combustion engine; GT, gas turbine; CC, combined cycle.

[a] For power generation through biomass gasification, the emissions from gasification are included in the upstream life cycles [156].

[b] Cofiring: only emissions for cofired biomass are given (average emissions for total generation would also include the part from coal).

[c] In the case of CHP, the net GHG emissions for electricity are derived by subtracting the emissions of a replaced natural gas-fired heating system from the total emissions of the cogeneration system.

[d] One estimate reaching 83 gCO$_2$-eq/MJ$_e$.

crops decreased significantly through mechanization in harvesting [133]. With regard to biomass logistics, Van den Wall Bake et al. [18] show that transportation costs for sugarcane mainly declined because of upscaling truck loads, automation of logistic systems and improved infrastructure. De Wit et al. [133] find similar mechanisms for eucalyptus in Brazil. Junginger et al. [152] find that transport cost for forest wood chips in Sweden have remained stable. However, technical improvement of the chippers has significantly reduced the supply costs of wood chips. Investment and O&M costs of the conversion process decline due to various learning mechanisms. In many cases, however, increasing scales of the conversion plants are found to be a key driver for cost reductions [18–20]. Findings of Junginger et al. [20] suggest that this is especially true for technologies that are developed on a global scale. For technologies developed on a local scale, learning-by-using and learning-by-interacting are indicated to play a major role in the reduction of costs.

4.4.5.2. Projections on learning induced cost reductions. Extrapolation of experience curves provides the opportunity to investigate potential future cost developments. Under a continued growth scenario for Brazilian sugarcane ethanol, Van den Wall Bake et al. [18] project that sugarcane production costs can decrease by 35–45% in 2020 compared to that during 2000–2004. Ethanol production costs are projected to decrease by 17–48% in the same time period. Hettinga et al. [19] estimate that corn production costs will decrease by approximately 30% until 2020, and ethanol production costs will decrease by about 46%, both compared to the 2000–2004 level. These

projections, however, are only based on further technological progress and do not take into account minimum attainable cost levels [19]. Therefore, studies by, for example, de Wit et al. [133] and IEA [52] do combine the experience curve approach with bottom-up analyses. In the combined approach, bottom-up analysis provides insight into the improvement potential of every supply chain component and derives minimum cost levels. The learning rate and the cumulative production, which is related to market volume, determine the speed at which costs decline and when minimum costs are achieved. Based on this approach, de Wit et al. [133] project that when the demand for SRC increases to an upper limit of 38 EJ in 2030, minimum production costs could be achieved in 2021–2025. At a demand of 20 EJ in 2030, the minimum cost level is projected to be reached between 2024 and 2030 [133]. In the Biofuels Roadmap, the IEA [52] assesses future production costs for different biofuels. Under favorable conditions (low impact of rising oil prices, rapid increase in market volume, high learning rate), advanced biofuels such as lignocellulosic ethanol and FT diesel can become cost competitive to petroleum gasoline and diesel by about 2030. In a more pessimistic scenario, costs decline more slowly and will permanently remain higher than in the optimistic scenario. By 2050, only first-generation ethanol and second-generation bio-SNG will be cost competitive to their fossil equivalents [52].

Finally, in the longer term, it can be expected that the increasing implementation of biorefinery concepts will influence the effect of technological learning. On the one hand, the variety in process configurations of biorefineries may slow down the speed at which the cumulative production doubles and costs decline. On

the other hand, biorefineries may be split into different components with their own investment and O&M costs, and associated progress ratios. These progress ratios may be derived from analog technologies that are operated at a larger scale.

4.5. GHG emissions

In this section we present GHG emission ranges from life-cycle inventories reported in the literature, Tables 11–14. These include both current data and projections for 2030. The total life-cycle emissions include the emissions from feedstock production and supply, and, wherever relevant, from energy inputs in the conversion process.

A literature review by NREL [155] shows that the GHG emissions from power generation do not differ significantly between combustion and gasification. In the case of CHP production, however, the power-heat ratio is smaller for biomass combustion than for gasification. As a result, combustion receives more credits and attains lower net emissions compared to gasification [54,156]. In addition, the applied allocation method causes the net emissions for current power generation in CHP plants to be smaller than zero (except for CHP from wheat- and corn-based biogas). This allocation method thus suggests that CHP, and more specifically combustion-based CHP, is the preferred option. However, this is not always the case. CHP is only attractive when a demand for heat exists in the immediate surroundings. Gasification has a higher electric efficiency compared to combustion, and may be preferred because electricity has a higher energy quality than heat. Also, through effective gas cleaning,

impurities can be removed from the product gas. This results in reduced corrosion problems, cleaner combustion and lower non-GHG emissions of for example sulfur and chlorine compounds [157].

The cultivation of wheat, corn, soybean and rapeseed is associated with high GHG emissions, and affects the life-cycle emissions of biogas CHP, biofuels and biomaterials. The major reason are N_2O emissions, which result from the use of fertilizers and agrochemicals [11,14,16,23,156,158]. However, there are large ranges for cultivation-induced emissions because of the sensitivity to the specific cultivation area and management system [23]. In contrast to cultivation, by-product credits from milling rapeseed and soybean can result in negative emissions for the processing and logistics step. This is to also true for jatropha. For palm oil, the credits are too small to attain negative emissions [23]. For sugarcane, perennials and short-rotation crops, the emissions related to cultivation are relatively small compared to the crops discussed above. In the data gathered by Hoefnagels et al. [23], it is assumed that inland transport distances are higher for perennials and SRC (260–500 km) compared to corn, wheat and sugarcane (50 km). This results in up to 5 times higher emissions related to logistics. Still, the total upstream emissions for perennials and SRC are smaller than those for corn and wheat, and smaller or comparable to the upstream emissions of sugarcane.

A few biofuel chains produce surplus power during the conversion process and can attain negative life-cycle emissions. These are short-term ethanol from eucalyptus and FT diesel from miscanthus and eucalyptus, and future sugarcane ethanol

Table 12
Cradle-to-grave GHG emissions of biofuels.

(gCO$_2$-eq/MJ fuel)		Timeframe	Cultivation		Processing & logistics[a]		Conversion		Life cycle[d] (WTW)		Reference
			Min	Max	Min	Max	Min	Max	Min	Max	
Ethanol	Corn	Europe – present	34.1	74.9	0.5		− 32.4	51.9	3.8	100.6	[23]
			54.5	*61.4*					55.9	61.4	[156]
		Europe – 2030 (whole crop)	*19.1*	*23.0*					19.6	23.6	[156]
		US – present	57.1		0.5		23.7		82.8		[23]
									56.4		[158]
	Wheat	Europe – present	39.0	67.5	0.6		− 22.0	38.5	20.6	86.1	[23]
			45.9	*61.0*					45.9	61.1	[156]
		Europe – 2030 (whole crop)	*16.7*	*18.0*					17.3	18.6	[156]
	Sugarcane	Brazil – present	6.9	15.1	0.5	1.4	− 5.8	2.2	10.8[c]	25.1[c]	[23]
									29.7[c]		[156]
		Brazil – future	6.2	6.9	0.5		− 52.1	− 9.7	− 40.4[c]	2.6	[23]
	Switchgrass	Europe – present	17.0		3.3		− 6.7	− 3.3	15.0	18.4	[23]
		Europe – 2030	12.3	12.4	3.3		− 6.7		10.3	10.5	[23]
	Miscanthus	Europe – present	10.8	11.0	3.3		− 3.3		11.8	12.0	[23]
		Europe – 2030	7.8	8.0	3.3		− 3.3		8.8	9.0	[23]
	Eucalyptus	Brazil – present	0.9		1.5		− 5.7		− 1.0	− 1.0	[23]
Biodiesel (FAME)	Oil palm	South East Asia – present	12.4	16.7	27.4[b]	36.2[b]	3.8	7.5	49.2	56.8	[23]
	Soy	US – present	107.1		− 10.4[b]		3.8		101.8		[23]
		Brazil – present	58.8	112.9	− 10.4[b]	14.3[b]	3.8	9.6	81.6	107.6	[23]
	Rapeseed	Europe – present	33.7	161.4	− 35.9	− 27.4	1.4	3.9	10.5	130.6	[23]
			8.9	*35.0*					9.5	35.5	[23]
		Canada – present	101.4		− 35.9		10.1		76.8		[23]
	Jatropha	Tanzania – present	33.9		− 11.8[b]		7.1	10.0	30.5	33.4	[23]
FT diesel	Switchgrass	Europe – present	17.3		2.3		− 8.8		11.3		[23]
		Europe – 2030	12.1		2.3		− 8.8		6.7		[23]
	Miscanthus	Europe – present	10.7		2.3		− 8.8		5.3	5.4	[23]
		Europe – 2030	7.7		2.3		− 8.8		2.3	2.5	[23]
			− 10.5						− 9.9		[156]
	Eucalyptus	Brazil – present	2.0		3.5		− 10.3		− 0.5		[23]
	SRC	Europe – 2030	*− 38.7*	*− 9.7*					− 35.6	− 9.1	[156]

Italic: emission range given under cultivation is total of emissions for cultivation, processing and logistics.
FAME, fatty acid methyl ester; WTW, well-to-wheel.

[a] Unless stated otherwise, logistics consists of inland transport of feedstock.
[b] Logistics includes transport of crude oil from the region of cultivation to the EU, where the conversion process takes place.
[c] Life-cycle emissions include international ship transport of ethanol from Brazil to EU.
[d] Fuel combustion in a reference Otto or diesel engine.

Table 13
Cradle-to-grave GHG emissions of biomaterials production.

	Process	Feedstock	Feedstock emissions (tCO$_2$-eq/t feed)	Life cycle (Cradle-to-grave emissions w/o energy recovery, tCO$_2$-eq/t product)				Life cycle (With energy recovery, tCO$_2$-eq/t product)		References
				Present		Projected: 2030 or beyond		Present	Projected	
				min	max	min	max			
Ethylene	Fermentation – ETE	Sugarcane	−0.54	−0.9	−0.1	−1.4	−0.6	−1.3	−1.8	[4,11,13,14]
		Corn	0.4	2.1	3.1	2				[11,13,14]
	Hydrolysis + fermentation – ETE	Ligno	0.16	−1.4	0.5	0				[11,13,14]
Olefins	Gasification, FT, steam cracking	Ligno		−3.8	−0.1					[13,14]
	Gasification, catalyzed synthesis, MTO	Ligno		1						[13,14]
Butanol		Sugarcane	−0.54	0.2	1.3	−2	−0.6	0.4	−2.2	[11]
		Corn	0.4	3	3.5	0.4	1.8			[11]
		Ligno	0.16			−1	0.3			[11]
PHA	Fermentation	Sugarcane	−0.54	−1.1	3.4	−0.5	0.2	−1.3	−0.7	[4,11]
		Corn	0.4	1.9	6.4	1.8				[11]
		Ligno				0.5				[11]
PLA	Fermentation	Sugarcane	−0.54	1.7	2.8	0.9	1.5	1.9	1.0	[4,11]
		Corn	0.4	3	4.2	2.2	2.5			[11,16]
		Ligno	0.16			1.4	1.7			[11]
PTT	Fermentation	Sugarcane	−0.54	3.7	3.9	3.4	4	3.3	3.0	[4,11]
		Corn	0.4	4.5	4.8	4.1	4.7			[11]
		Ligno	0.16			3.7	4.3			[11]

Table 14
Cradle-to-grave GHG emissions of fossil reference products.

Biomass product	Fossil reference product	Today 2010	Projection 2030	References
Energy		(gCO$_2$-eq/MJ product)		
Heat	Heat (hot water)	95.3[a]	91.5[a]	[21,27,156]
		(EU-25)		
Power	Power	134.4	113.0	[21,156,159,160]
		(EU-27 mix)		
Ethanol	Gasoline	90	73.6[b]	[21,156,161–164]
Diesel (bio-, renewable, and FT diesel)	Diesel	86	70.3[b]	[21,156,161–164]
Materials		(tCO$_2$-eq/t product)[c]		
Ethylene/olefins	Ethylene/olefins	4.4	4.2	[11]
Butanol	Butanol	4.3	4.1	[11]
PHA	PE	4.7	4.5	[11]
PLA	PET	5.5	5.3	[11]
PTT	PTT	5.2	5.0	[11]

[a] Based on natural gas combustion.

[b] For gasoline and diesel, we assume that the WTW emissions reduce with 1% per year [163,164]. If marginal fossil fuels (tar sands) would be used in the future, this would negatively affect the GHG emission balance of fossil reference products. We do not take this into account here.

[c] System boundary: cradle to grave (without use phase), incineration without energy recovery at end of lifetime [11]; for the projections, an emission reduction rate similar to heat is assumed.

[23,156]. With regard to biomaterials, the production of surplus power can result in negative life-cycle emissions for ethylene, future butanol, and for olefins production via FT synthesis. This is however only true for sugarcane and lignocellulosic feedstocks. Environmental assessments of PHA find a relatively wide range in life cycle emissions. This reflects the variety of options for the production process. Although negative emissions are found in some cases, a review by Chen and Patel [96] indicates that high processing requirements for PHA production (downstream processing and wastewater treatment) involve substantial direct and indirect energy use, which results in an unattractive GHG balance.

4.6. Synthesis: selection of value chains

Considering the cost and emission data collected, we find that there are incongruences in the availability of data. The number of bioenergy technologies for which cost data is available is larger

than the number for which GHG emission data is found. Also, we collected more current cost and emission data than projected data for both bioenergy and biomaterials. As a result, we can calculate the levelized production costs for all technologies considered in Section 4.4. But, the number of current and future biomass value chains for which we can calculate GHG abatement costs is limited by the availability of GHG emission data. Below, we define the biomass value chains (type of feedstock, pretreatment and logistics for each conversion technology) and select the input data needed to calculate the levelized costs.

4.6.1. Selection of input cost and emission data

For each conversion technology, we compose a biomass value chain by defining the type of feedstock, pretreatment and logistics (Table 15). Based on the cost figures found for feedstock production, pretreatment and transportation (Sections 4.2 and 4.3),

Table 15 shows which values for the feedstock delivery costs are chosen to be used in the calculation of levelized production costs and in the sensitivity analysis. For most feedstocks, we use a cost level that is representative for a region where the feedstock is typically produced and converted. For wood pellets we assume ocean freight from Canada to Europe. As it is expected that the importance of pretreatment and international trade of lignocellulosic energy crops will increase in the future, it is preferred to take related biomass value chains into account. Due to a lack of

emission data, however, our selection is limited to non-pretreated woody energy crops which are cultivated and converted in the same region. The production costs of biomaterials are based on the price of fermentable sugar. To give a representation of the production costs based on Brazilian sugarcane, we use a price of 141 $/tonne fermentable sugar (3.4 $/GJ sugarcane). For the USA and EU, we use a fermentable sugar price of 250 $/tonne sugar (13.3 $/GJ corn). Higher sugar price levels are represented by the world raw sugar price (contract 11): the 10-year average sugar

Table 15
Feedstock types and costs used for levelized cost calculations.

Product	Feedstock	Region feedstock cultivation	Transport mode	Region final conversion	Feedstock delivery cost ($/GJ)[a]				Feedstock yield (GJ/(ha yr))	
Energy					Present	Sensitivity	2030	Sensitivity	Present	2030
Heat, combustion	Pellets (sawdust, shavings)	Canada	Ocean vessel	EU	9	5–12	4.5	3–7	20	25
Power/CHP, combustion	Pellets (sawdust, shavings)	Canada	Ocean vessel	EU	9	5 –12	4.5	3–7	20	25
	MSW	n/a	Local truck	EU	1.5	0.5–3	1.5	0.5–3	n/a	n/a
Power, AD	Manure, biowastes	n/a	Local truck	EU	1.5	0.5–3	1.5	0.5–3	n/a	n/a
Power/CHP, gasification	Pellets (sawdust, shavings)	Canada	Ocean vessel	EU	9	5–12			20	25
	Woody energy crops	EU/LA	National truck	EU/LA			3.5	2–5		280
Ethanol (1st gen.)	Sugarcane	Brazil	National truck	Brazil	3.4	2–6.5			380	460
	Corn	USA	National truck	USA	9.0	4–10			145	175
	Wheat	EU	National truck	EU	17	15–20	15.5	13–18	130	235
Biodiesel	Soy oil	USA/Brazil	National truck	USA/Brazil	15	10–25			20	25
	Palm oil	Asia	National truck	Asia	23	13–27			160	195
	Rapeseed oil	EU	National truck	EU	26	15–32	13	11–15	50	60
Renewable diesel	Soy oil	USA	National truck	USA	15	10–25			20	25
2nd Gen. fuels	Woody energy crops	EU/LA	National truck	EU/LA	4.5	2.5–6.5	3.5	2–5	190	280
Materials					Feedstock costs ($/tonne)					
Fermentation	Fermentable sugar	Brazil	National truck	Brazil	141	73–250	141	73–250	9.2 (t sugar/ha)[b]	11.1
		USA/EU	National truck	USA/EU	250	141–418	209	141–418	7.7 (t sugar/ha)[c]	9.3
	Woody energy crops	EU/LA	National truck	EU/LA	86	44–113			190	
Gasification	Woody energy crops	EU/LA	National truck	EU/LA	86	44–113			190	

n/a not applicable.

[a] Feedstock delivery costs: total costs to deliver feedstock to the conversion plant (roadside costs+pretreatment+transportation).
[b] 0.42 t Fermentable sugar/t dm sugarcane [147,166], current sugarcane yield 380 GJ/(ha yr), projected 460 GJ/(ha yr).
[c] 0.94 t Fermentable sugar/t dm corn [11], current corn yield 145 GJ/(ha yr), projected 175 GJ/(ha yr).

Table 16
Current and projected fossil resource prices [63].

Fossil resource	Applications	Price current		Price projection 2030[a]		
		Average	Sensitivity	Average	Sensitivity	
Oil	Heat, power, fuels, materials	10.4 (75)	8.3–12.5 (60–90)	15.3 (110)	12.5–18.1 (90–130)	$/GJ ($2009/bbl)
Natural gas	Heat, power	6.4 (7.4)	3.5–8.1 (4.1–9.4)	11.1 (12.9)	8.1–13.7 (9.4–15.9)	$/GJ ($2009/MMBTU)
Coal	Power	3.3 (92)	2.8–4.0 (77–110)	3.8 (105.6)	2.4–4.1 (66.3–112.5)	$/GJ ($2009/tonne)

[a] Based on WEO 2010 scenarios: average for New Policies scenario, lower sensitivity value for 450 pp scenario, higher sensitivity value for Current Policies scenario [63].

Table 17
By-product revenues used for levelized cost calculations.

Product		Byproduct(s)	By-product revenue	References
Heat		–	–	
Power		–	–	
CHP		Steam (large-scale CHP $> 25MW_e$)	4.85 $/GJ steam[a]	[27]
		Hot water (small-scale CHP $< 10MW_e$)	12.51 $/GJ hot water[b]	[27]
Ethanol	Sugarcane	Sugar[c]	4.26 $/GJ feed	[7,27]
	Corn	DDGS	1.56 $/GJ feed	[7]
	Wheat	DDGS	1.74 $/GJ feed	[7]
Biodiesel		Glycerol	0.58 $/GJ feed	[7]
2nd Generation fuels		Electricity	0.054 $/kWh$_e$	[28]
Ethylene/olefins		Electricity	0.054 $/kWh$_e$	[28]

[a] 75% of heat output is sold.
[b] 33% of heat output is sold.
[c] In Brazil, sugarcane ethanol is often produced in an integrated sugar-ethanol plant; we treat sugar as byproduct, and assume that 50% of the sucrose is used for ethanol production and 50% for sugar production.

price is 276 $/tonne, the 5-year average price is 347 $/tonne [165]. For the fossil feedstocks, we use present and projected fossil resource price data from the IEA World Energy Outlook 2010 [63], Table 16. Finally, we select a fixed by-product revenue for each by-product type, based on economic values found in the literature (Table 17).

The biomass value chains composed for biofuels and biomaterials correspond to the value chains defined in the literature to calculate the life-cycle emissions. For heat and power production, however, emissions are often given for other feedstock types like wood chips. As we consider wood pellets shipped from Canada to Europe, we recalculate the total life-cycle emissions by assuming that only the upstream emissions change (Table 18).

5. Results

5.1. Levelized costs

5.1.1. Bioenergy

In Fig. 4, the levelized costs of biomass-based heat, power and fuel production are compared to the price ranges of their fossil equivalent products. At a fossil oil price of 75 $_{2009}$/bbl$_{oil}$ and a natural gas price of 7.4 $_{2009}$/MMBTU$_{NG}$, large-capacity wood pellet-fueled domestic and district heating (15 $/GJ for 100 kW domestic, and 18 $/GJ for 5 MW district heat) can only be cost competitive to capital intensive fossil heating systems.

With regard to power generation (power only and CHP), a significant variety in levelized costs is found. None of the technologies are cost competitive with fossil-based electricity (which costs up to 20 $/GJ$_e$). Considering large-scale systems, we found that direct and parallel cofiring attain lower investments costs than the IGCC. At a wood pellet price of 9 $/GJ, the costs for cofiring (28–34 $/GJ$_e$ at 5–100 MW$_e$) are comparable to a 250 MW IGCC (25–33 $/GJ$_e$). Power production in a 50 MW$_e$ IGCC costs 29–40 $/GJ$_e$. Biomass combustion steam cycles can potentially also attain lower investment costs compared to an IGCC. However, lower efficiencies for biomass combustion steam cycles affect the levelized costs significantly. At a feedstock price of 9 $/GJ, the costs for biomass combustion steam cycles are 45–47 $/GJ$_e$ at 100 MW$_e$ and about 50–56 $/GJ$_e$ at 20 MW$_e$. At a low feedstock cost level of 3 $/GJ (wood logs, residues) the cost for combustion would be 22–33 $/GJ$_e$. Similar cost levels are found by Bauen et al. [6]. Steam cycle technologies based on MSW combustion have both high investment costs and low efficiencies, resulting in levelized costs of 75 $/GJ$_e$. Small-scale CHP plants (gas engines and turbines, steam engine, ORC and stirling engines, < 1 MW$_e$) are very costly at 78–122 $/GJ$_e$. Although projected cost reductions to 48–87 $/GJ$_e$ in 2030 are

Table 18
Total life-cycle emissions for heat and power production based on combustion or gasification of wood pellets shipped from Canada to Europe[a].

				Life cycle (gCO$_2$-eq/ MJ product)	
				min	max
Heat	Domestic		Present	13.4	17.6
			2030	12.2	15.5
	District		Present	12.0	16.0
			2030	9.6	16.8
Power[b]	Cofire[c]	Power	Present	25.3	21.4
		CHP	Present	−102.3	−85.8
	Combustion	Stirling – CHP	Present	−249.5	−228.5
		ORC – CHP	Present	−406.5	−356.8
		Steam engine – CHP	Present	−368.1	−308.9
	Gasification	IGCC – power	Present	73.8	
		IGCC – CHP	Present	−8.9	
		Indirect cofiring – power	Present	75.4	
		Micro-gas turbine – CHP	Present	−30.6	
		ICE – CHP	present	−52.1	−50.0

ORC, Organic Rankine Cycle; ICE, internal combustion engine; IGCC, integrated gasification combined cycle.

[a] Upstream emissions for wood pellets (pelletization of sawdust and shavings in Canada and pellet ocean shipping to Europe): 8.6 gCO$_2$-eq/MJ pellets [44], no projected reduction in emissions [156].
[b] In the case of CHP, the net GHG emissions for electricity are derived by subtracting the emissions of a replaced natural gas-fired heating system from the total emissions of the cogeneration system.
[c] Cofiring: only emissions for cofired biomass are given (average emissions for total generation would also include the part from coal).

substantial (feestock cost 3.5 $/GJ for woody energy crops), and fossil energy prices are expected to increase, these technologies do not become cost competitive in the longer term. For a woody energy crop-fueled IGCC (feedstock 3.5 $/GJ) we find production costs of 11–26 $/GJ in 2030. In the literature, power generation costs for an IGCC are projected to be 8–19 $/GJ [[144];[6] in:[2]]. Unfortunately, no projected levelized costs could be calculated for combustion steam cycles. A review study by the National Research Council finds no cost reductions between 2010 and 2020 [167].

Of the various first-generation biofuels, only large-scale ethanol production from low-cost Brazilian sugarcane (9–12 $/GJ$_{EtOH}$ at 3.4 $/GJ$_{sugarcane}$) attains lower production costs than petrochemical gasoline (16 $/GJ$_{gasoline}$). The costs of US corn ethanol (17–21 $/GJ$_{EtOH}$ at 9.0 $/GJ$_{corn}$), soy-based biodiesel and renewable diesel (17–19 $/GJ$_{diesel}$ at 15 $/GJ$_{soy oil}$) are comparable to the costs of fossil gasoline and diesel (16 $/GJ$_{diesel}$). Wheat ethanol (33–38 $/GJ$_{EtOH}$ at 17 $/GJ$_{wheat}$) and rapeseed biodiesel (39–49 $/GJ$_{deisel}$ at 26 $/GJ$_{rapeseed oil}$) have the highest levelized cost levels. In the
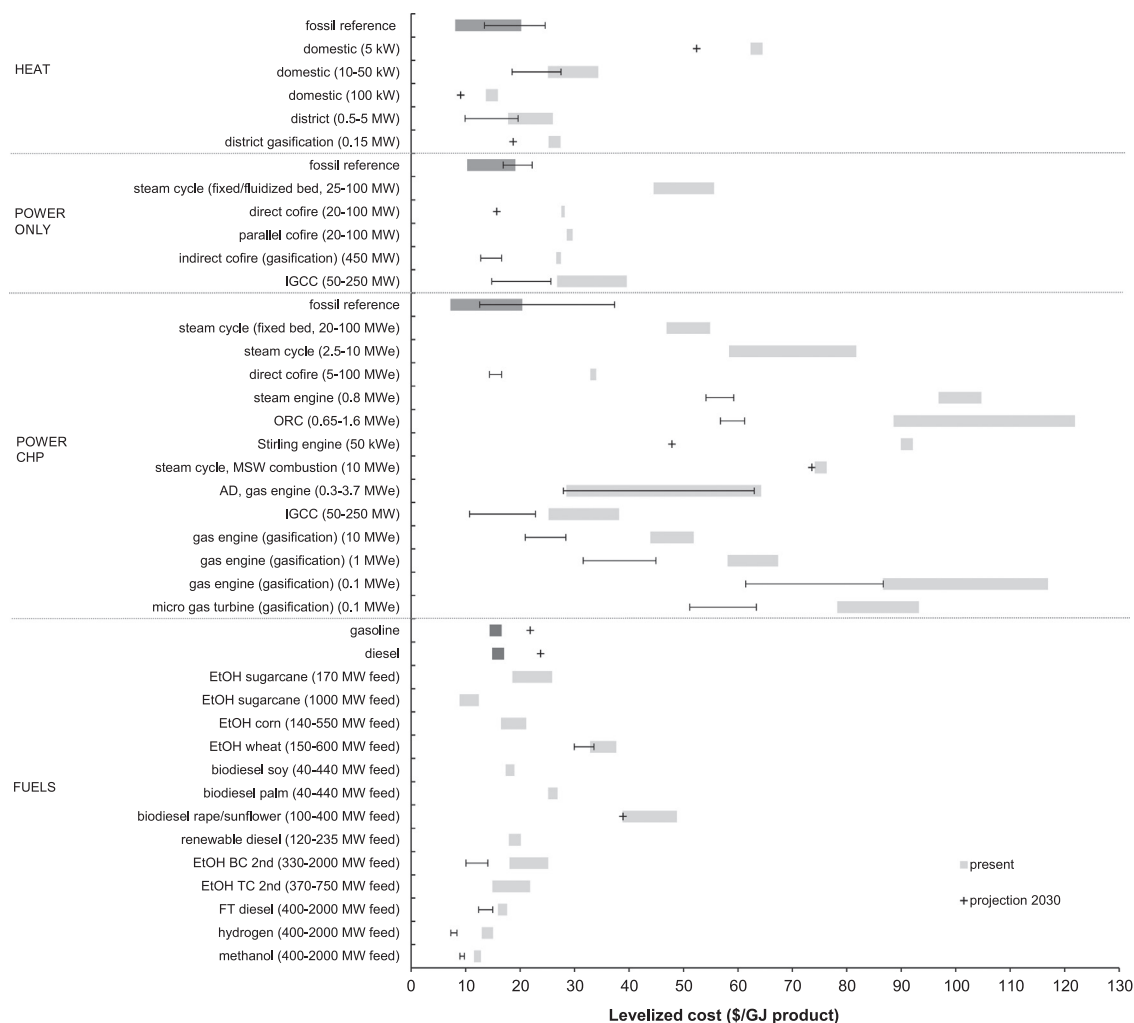
Fig. 4. Levelized costs of heat, power and fuels. Light gray bars: current costs of bio-energy; dark gray bars: current costs of fossil-based energy; black line: range of cost projections for 2030 based on multiple data sets; black plus sign: cost projection for 2030 based on one data set. CHP: levelized costs for power include a revenue for heat (Table 17). Fossil reference current: 75 $_{2009}$/bbl_oil; 2030: 110 $_{2009}$/bbl_oil (Table 16).
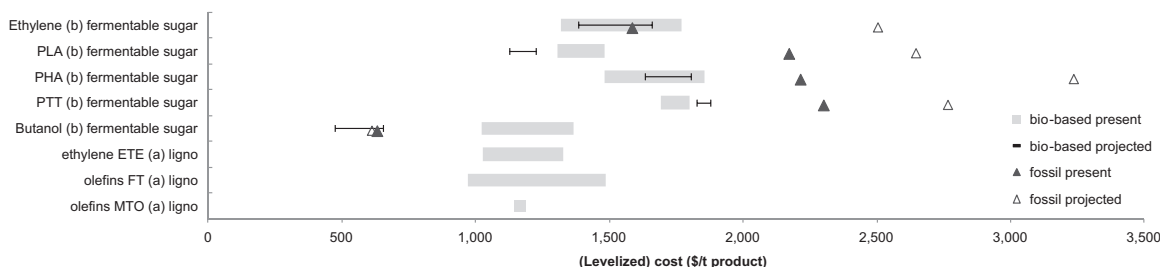
Fig. 5. Levelized cost for biomaterials and biochemicals. (a) Levelized costs for technologies considered by Ren et al. [14]; (b) Estimated cost range for materials based on the work of Saygin et al. [4] using a fermentable sugar price range of 141 $/t_{fermentable sugar} (Brazilian sugarcane, 3.4 $/GJ) to 250 $/t_{fermentable sugar} (USA/EU, 13.3 $/GJ_corn). Light gray bars: current costs of bio-materials; black line: cost projections biomaterials for 2030; dark gray filled triangles: current cost of fossil equivalents; unfilled triangle: cost projection fossil equivalents for 2030. Fossil reference current: 75 $_{2009}$/bbl_oil; 2030: 110 $_{2009}$/bbl_oil (Table 16).

literature, the costs of commercial biofuels are largely comparable to our results (see table 2.7 in Chum et al. [2]). Disparities in production costs can mainly be explained by differences in feedstock costs used for the calculations.

The results for second-generation fuels show that methanol and hydrogen attain the lowest production costs, which are competitive to fossil diesel and gasoline. We find methanol production costs of about 12 $/GJ_{MeOH} (4.5 $/GJ for woody energy crops). For comparison, a review by IEA-ETSAP [168] shows that cost estimates in the literature mainly range between 9–36 $/GJ_{MeOH} (no feedstock costs given), depending on plant setup,

production capacity and local conditions. The productions costs of natural gas-based methanol are about 5–13 $/GJ_{MeOH} [168]. By 2030 the costs of lignocellulosic-based fuels are projected to decline with rates up to 50% to a level comparable with present large-scale sugarcane ethanol production.

5.1.2. Biomaterials

Fig. 5 shows the (levelized) production costs of biomaterials. The figure indicates that only butanol and corn-based ethylene are not cost competitive to their fossil equivalent. Comparison with

the cost estimates of Hermann and Patel [15] (based on fossil oil price of 25 $_{2009}$/bbl$_{oil}$) shows that the economic viability of biomaterials is substantially higher at a fossil oil price of 75 $_{2009}$/bbl$_{oil}$ because the oil price largely affects the costs of materials from fossil feedstocks. As the costs of fossil-based materials increase at a higher rate with the oil price than the costs of biomaterials, the production of butanol is projected to become economically feasible in the longer term, and all biomaterials are projected to improve their economic competitiveness.

For fermentation-based ethylene, our calculations based on data published in [15,93,150] result in higher production costs (1320 $/tonne for 3.4 $/GJ$_{sugarcane}$ to 1770 $/tonne for 13.3 $/GJ$_{corn}$) compared to the calculation based on data from Ren et al. [14] (1030–1330 $/tonne for 4.5 $/GJ$_{woody\ energy\ crops}$). IEA-ETSAP reports the production costs of sugarcane-based ethylene in Brazil and India to be around 1100 $/tonne [95]. In other regions, the production costs are higher. For US corn-based ethylene the costs are just below 1900 $/tonne [95]. The report also states that current costs for petrochemical ethylene are 1000–1200 $/tonne in most regions (75 $_{2009}$/bbl oil) [95]. This is lower than the 1600 $/tonne found in our analysis at the same oil price. Although the cost figures differ between sources, they show that ethylene production from biomass is only economically feasible at low feedstock prices and high oil prices.

For biochemical butanol production, Tao and Aden [64] estimate the future production costs to be just below 1000 $/tonne. At 470–650 $/tonne, our long-term projection is significantly lower. For other materials, only selling prices are mentioned in the literature. For PLA, we find production costs of 1300 $/tonne (Brazilian sugar) to 1480 $/tonne (US/EU sugar), while selling prices are about 1800–3500 $/tonne [76,104]. PHA prices are 3500–4700 $/tonne for bulk applications [76,104]. Our calculations result in costs of 1480–1860 $/tonne. The considerable difference between production costs found in our analysis and selling prices for PLA and PHA can be explained by risks of market introduction of new materials and the low volumes in which these materials are sold, resulting in high costs for selling efforts like marketing. Another reason could be the fermentable sugar prices used in our calculations, which are lower than the current world raw sugar price.
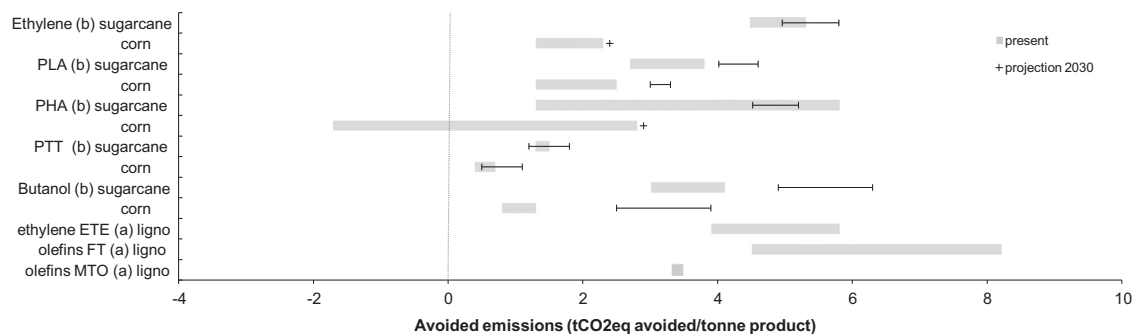
5.2. Avoided emissions

5.2.1. Bioenergy

Fig. 6 shows that most bioenergy products do avoid emissions. Because system expansion is applied, the net emissions of CHP power are negative. As a result, we find that CHP systems for power production avoid significantly more emissions compared to other bioenergy systems. Small-scale biomass combustion-based CHP technologies, which have low power-heat ratios, avoid most emissions. Biogas CHP based on manure and biowastes performs comparable to gasification CHP.

In Section 4.5 life-cycle emissions as low as 3.8 gCO$_2$-eq/MJ$_{EtOH}$ were found for corn ethanol, resulting in an emission reduction of 86 gCO$_2$-eq/MJ. However, the figures also showed that a maximum
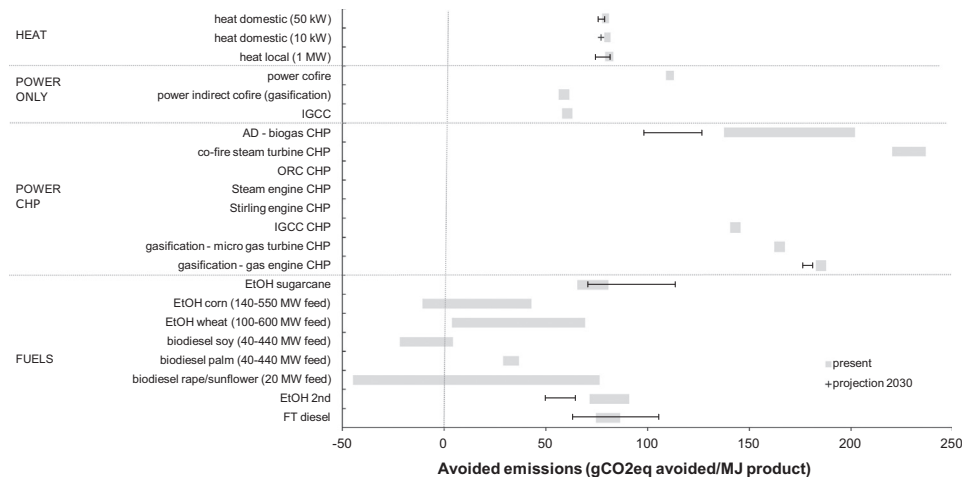

Fig. 6. Avoided emissions of bioenergy. Light gray bars: current avoided emissions; black line: range of avoided emissions for 2030 based on multiple data sets; black plus sign: emission reduction for 2030 based on one data set.

Fig. 7. Avoided emissions of biomaterials and biochemicals. (a) Emission reduction for technologies considered by Ren et al. [14], (b) emission reduction for materials considered by Saygin [4]: projected avoided emission levels for lignocellulosic energy crops lie between projected emission reduction levels of corn and sugarcane. Light gray bars: current avoided emissions; black line: range of avoided emissions for 2030 based on multiple data sets; black plus sign: avoided emissions for 2030 based on one data set.
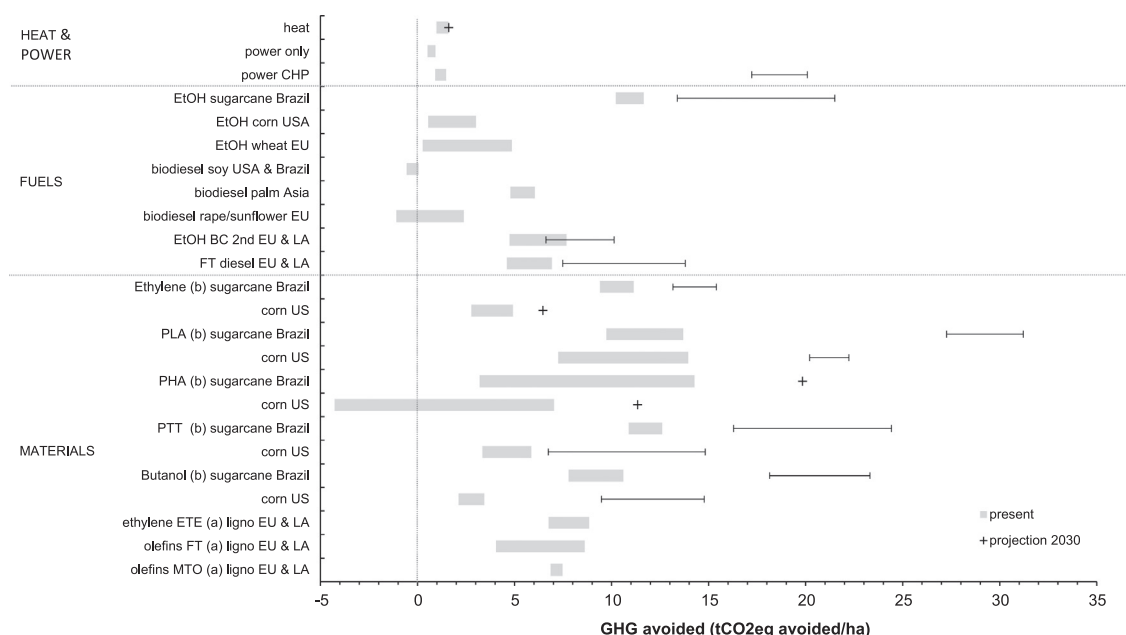
Fig. 8. Avoided emission per hectare. Materials: (a) emission reduction for technologies considered by Ren et al. [14], (b) emission reduction for materials considered by Saygin [4]. Light gray bars: current avoided emissions; black line: range of avoided emissions for 2030 based on multiple data sets; black plus sign: avoided emissions for 2030 based on one data set.
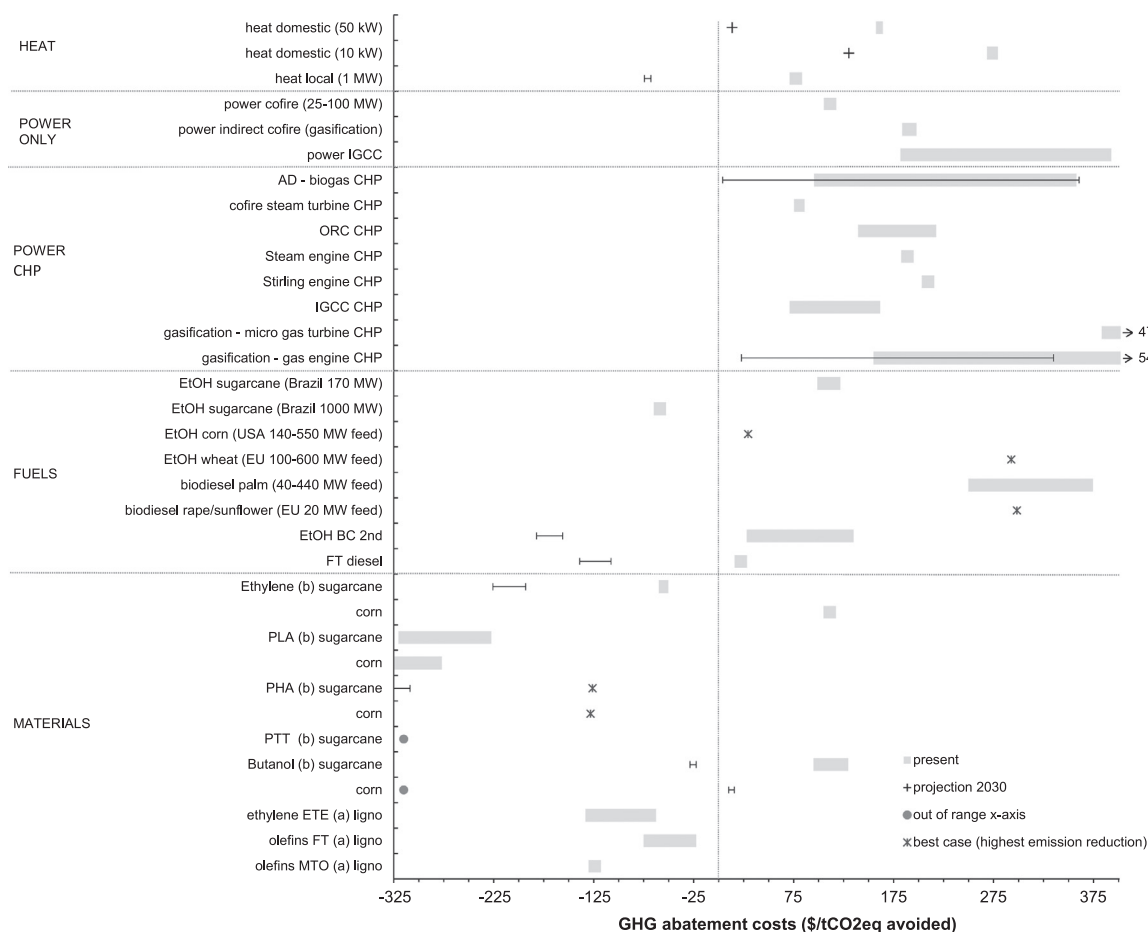
Fig. 9. GHG abatement costs. Materials: (a) abatement costs for materials considered by Ren et al. [14]; (b) abatement costs for materials considered by Saygin [4]. Light gray bars: current abatement costs; black line: range of abatement costs for 2030 based on multiple data sets; black plus sign: abatement cost for 2030 based on one data set; asterisks: best case, abatement cost at the highest emission reduction: lower or no reduction found as well; dot: GHG abatement costs fall out of range on the x-axis (PTT sugarcane: lower than −325 $/tCO2-eq$_{avoided}$; butanol corn: higher than 400 $/tCO2-eq$_{avoided}$). Soy biodiesel and corn-based PTT attain very low and/or negative emissions and were left out of the figure. Fossil reference cost levels applied for bioenergy: heat 12.4 $/GJ, power 15.8 $/GJ, power (CHP) 15.1 $/GJ, gasoline 15.5 $/GJ, diesel 16 $/GJ.

reduction of 43 gCO_2-eq/MJ is more likely. Larger reductions were only found in Europe for high by-product credits for the conversion process. We do not include the high reduction level in Fig. 6, and find that sugarcane ethanol (66–81 gCO_2-eq$_{avoided}$/MJ$_{EtOH}$) performs better compared to corn ethanol. Ethanol production from wheat performs comparable or slightly better than production from corn. The performance of biodiesel depends greatly on the feedstock. The use of soy (Brazil and US) does not result in emission reductions, or only a very small reduction in Brazil (4.4 gCO_2-eq$_{avoided}$/MJ$_{diesel}$). For rapeseed, a very large range is found (−45 to 77 gCO_2-eq$_{avoided}$/MJ$_{diesel}$), which is mainly caused by a high emission range found for feedstock cultivation (Table 12).

The highest emission reductions are achieved by lignocellulosic ethanol and FT diesel (72–91 gCO_2-eq$_{avoided}$/MJ$_{fuel}$). According to the projections for 2030 the emissions related to these fuels will decrease even further. However, as the WTW emissions of fossil-based fuels are projected to decrease as well due to improved engine efficiencies (tar sands are not taken into account), the reduction of emissions can become smaller (50–65 gCO_2-eq$_{avoided}$/MJ$_{EtOH}$ and 63–106 gCO_2-eq$_{avoided}$/MJ$_{diesel}$). In the case of sugarcane ethanol, the increasing amount of electricity sold to the grid will reduce the emissions and the amount of emissions avoided will increase. At the same time, however, the implementation of renewable energy technologies increases and causes a reduction in the credit for exported electricity.

5.2.2. Biomaterials

In Section 4.5, it was shown that, comparable to biofuels, the life-cycle emissions of materials produced from sugarcane are lower than the emissions of corn-based materials. In Fig. 7, this results in a higher emission reduction for materials from sugarcane. In the projections of Hermann et al. [11], reductions for lignocellulosic biomass are in between those of sugarcane and corn. Emission reductions are the highest for ethylene from sugarcane (4.5–5.3 tCO_2-eq$_{avoided}$/t$_{ethylene}$) and lignocellulosic biomass (3.9–5.8 tCO_2-eq$_{avoided}$/t$_{ethylene}$), and for olefins production via FT synthesis (4.5–8.2 tCO_2-eq$_{avoided}$/t$_{olefins}$). We find a wide range in avoided emissions in the life cycle of PHA. The discussion in Section 4.5 made it clear that a low emission reduction level (or no emission reduction in the case of corn) is more likely than a high reduction.

5.2.3. Avoided emissions per hectare

Fig. 8 presents the emission abatement for energy and materials on a hectare basis. As present heat and power production is based on the combustion of wood residues, which have a low yield per hectare, the GHG emission abatement level per hectare is low (0.5–1.7 tCO_2-eq$_{avoided}$/ha). The projection for a gas engine CHP, however, shows that the abatement can increase significantly when lignocellulosic energy crops will be applied (17–20 tCO_2-eq$_{avoided}$/ha). Biofuels and biomaterials avoid most GHG emission per hectare when based on sugarcane (10–12 tCO_2-eq$_{avoided}$/ha for ethanol and 10–14 tCO_2-eq$_{avoided}$/ha for PLA). These are followed by fuels and materials from lignocellulosic energy crops (5–8 tCO_2-eq$_{avoided}$/ha for ethanol and 7–9 tCO_2-eq$_{avoided}$/ha for ethylene).

5.3. GHG abatement costs

At the average production costs of fossil-based products (Fig. 4), the majority of bioenergy products are not economically competitive compared to their fossil reference. On the other hand, Fig. 6 shows that most value chains avoid emissions compared to their fossil equivalent. This results in positive abatement costs (Fig. 9). Negative abatement costs are found for low-cost Brazilian sugarcane used in the large-scale production of ethanol (−65 to −53

$/$tCO_2$-eq$_{avoided}$) and most biomaterials (e.g. −60 to −50 $/$tCO_2$-eq$_{avoided}$ for ethylene). In the case of corn (USA) and wheat (EU) ethanol, soy and rapeseed biodiesel (US/Brazil and EU, respectively), and corn butanol, PHA and PTT,[8] the emission reduction can be very small or bio-based processes can even cause larger emissions compared to the fossil reference. In case of very small emission reductions, the GHG abatement costs become very large (either positive or negative) and are therefore not meaningful in comparison with other biomass value chains. We also find high abatement costs for small-scale gasification technologies (383–548 $/$tCO_2$-eq$_{avoided}$). This is a result of the high production costs for power generation compared to the fossil reference.

As the prices of fossil products are projected to increase in the future, while production costs of bioenergy and biomaterials are likely to decline, more conversion routes can become economically feasible and attain negative abatement costs. The large negative abatement costs of future lignocellulosic biofuels (−182 to −108 $/$tCO_2$-eq$_{avoided}$), for example, are not caused by small emission reductions, but by a high cost difference compared to the fossil reference.

5.4. Sensitivity analysis

In Figs. 10–12, we analyze the sensitivity of the GHG abatement costs for changes in biomass feedstock costs, in fossil resource prices and in the discount rate. We perform the analysis for a selection of biomass value chains that attained negative or relatively low positive abatement costs.

Fig. 10 shows that the abatement costs of current heat and power production remain positive when the feedstock costs decrease by 44% from 9 to 5 $/GJ. Considering the most cost-competitive technologies, the abatement costs of large-scale district heating decline from 79 to 15 $/$tCO_2$-eq$_{avoided}$. The abatement costs of cofiring-based power generation drop from 113 to 24 $/$tCO_2$-eq$_{avoided}$. Only in the case of future domestic heating, the feedstock costs determine whether the abatement costs become negative or positive. The system attains negative abatement costs (−10 $/$tCO_2$-eq$_{avoided}$) when the costs of wood pellets decline from 4.5 to 3 $/GJ.

For all current biofuel and biomaterial value chains considered in Fig. 10, the point where GHG abatement costs turn from negative to positive is within the feedstock cost range considered. The results suggest that the sensitivity to the feedstock costs is larger for the GHG abatement costs of first-generation biofuels than of second-generation fuels. The abatement costs of sugarcane ethylene are less sensitive to feedstock costs than the abatement costs of sugarcane ethanol. This can be explained by the longer chain of capital costs (more processing steps), due to which the importance of the feedstock delivery costs becomes smaller.

A change in the fossil resource prices has the most impact on the production costs of fossil diesel and ethylene. The effect is the lowest for power generation from coal (no CHP). However, only when the initial abatement cost level was found to be close to zero, the fossil resource price level determines whether the biomass value chain is cost competitive to the fossil reference or not (Fig. 11). This applies to current FT diesel and sugarcane ethylene production, and to future large-scale domestic heating and gas engine CHP.

Within the range of 3–10% for the discount rate, only the longer-term abatement costs of domestic heating and gas engine CHP change from negative to positive (Fig. 12). At a low discount rate of 3%, the abatement costs of current FT diesel production attain 1.6 $/$tCO_2$-eq$_{avoided}$.

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[8] For PTT, the relatively small share of bio-based compounds in the polymer limits the emission reduction potential.
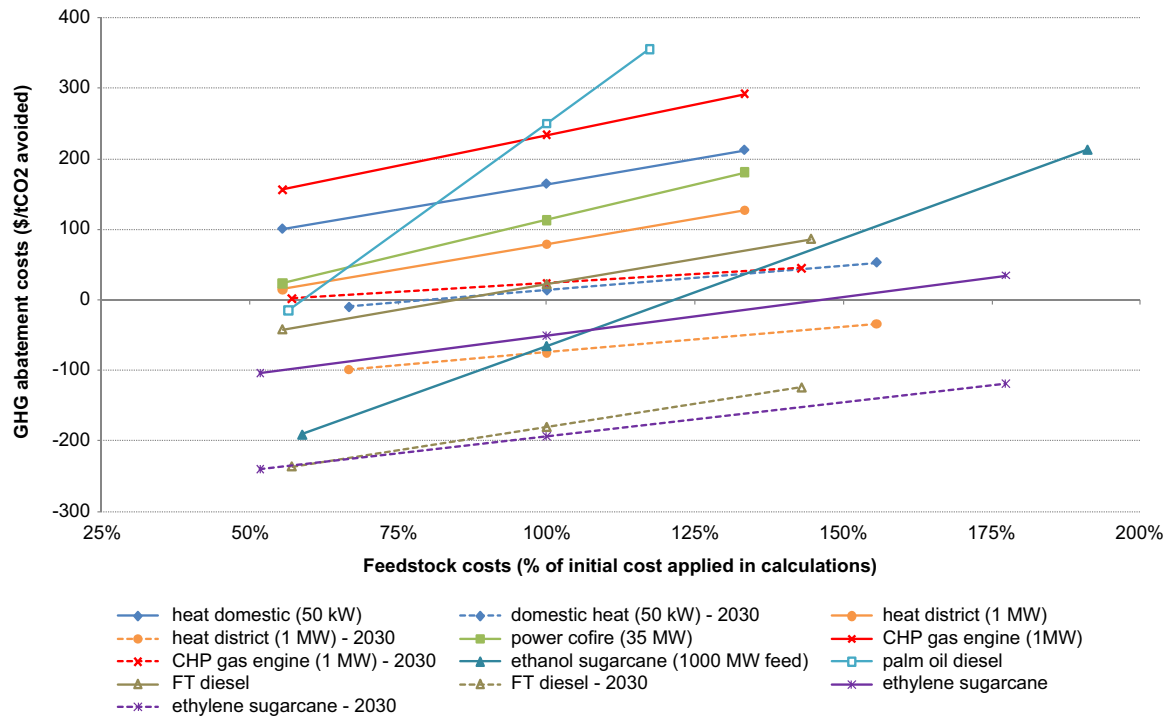
Fig. 10. GHG abatement costs as a function of the biomass feedstock delivery costs.
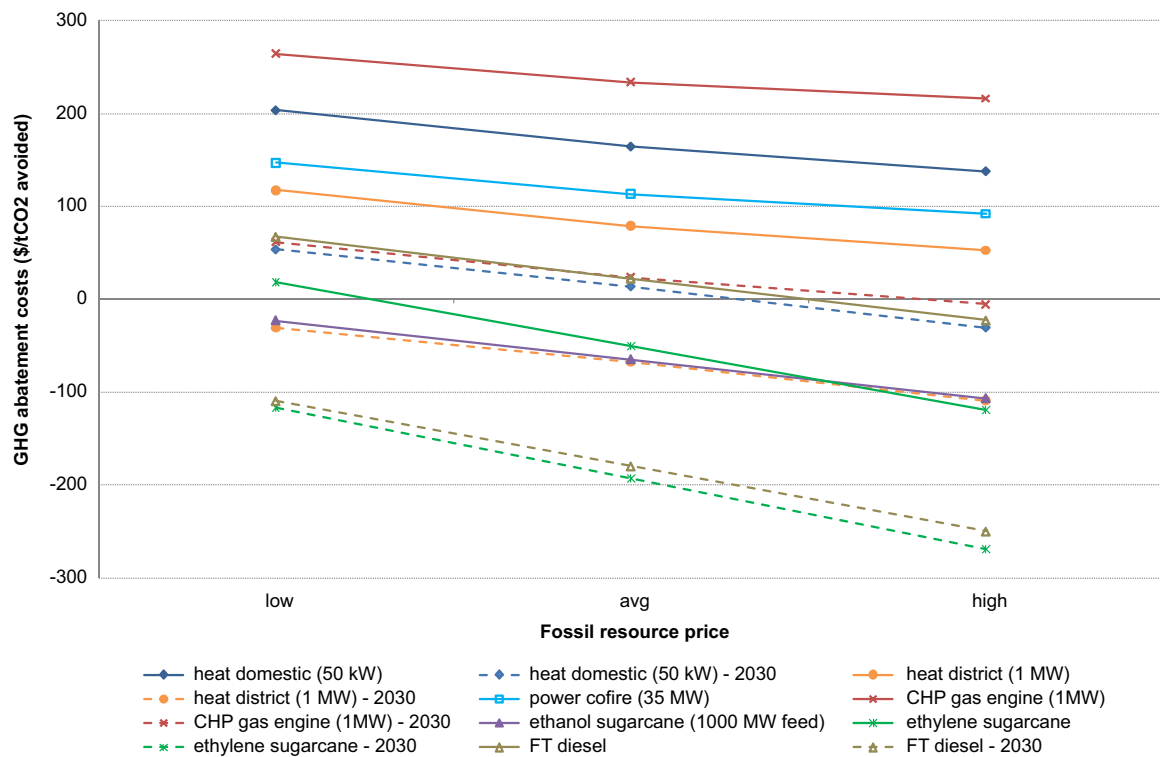

Fig. 11. GHG abatements costs as a function of the fossil resource prices (see Table 16 for the applied fossil resource price ranges).

Fig. 13a–d compares the impact of the different parameters on the GHG abatement costs of four biomass value chains. For heat and power production in the longer term, fossil fuel prices influence the abatement cost most (difference of 28–45 $/tCO$_2$-eq$_{avoided}$). The impacts of the discount rate and feedstock costs are a bit smaller (difference of 21–40 $/tCO$_2$-eq$_{avoided}$). For ethylene, the range of the fermentable sugar price is large,

and has significant impact on the abatement costs (change up to 85 $/tCO$_2$-eq$_{avoided}$). The feedstock costs also have the largest influence on the abatement costs of FT diesel (difference of 64 $/tCO$_2$-eq$_{avoided}$). The discount rate has a relatively small effect on the abatement costs of FT diesel (change of 17–21 $/tCO$_2$-eq$_{avoided}$) and ethylene (change of 3 $/tCO$_2$-eq$_{avoided}$).
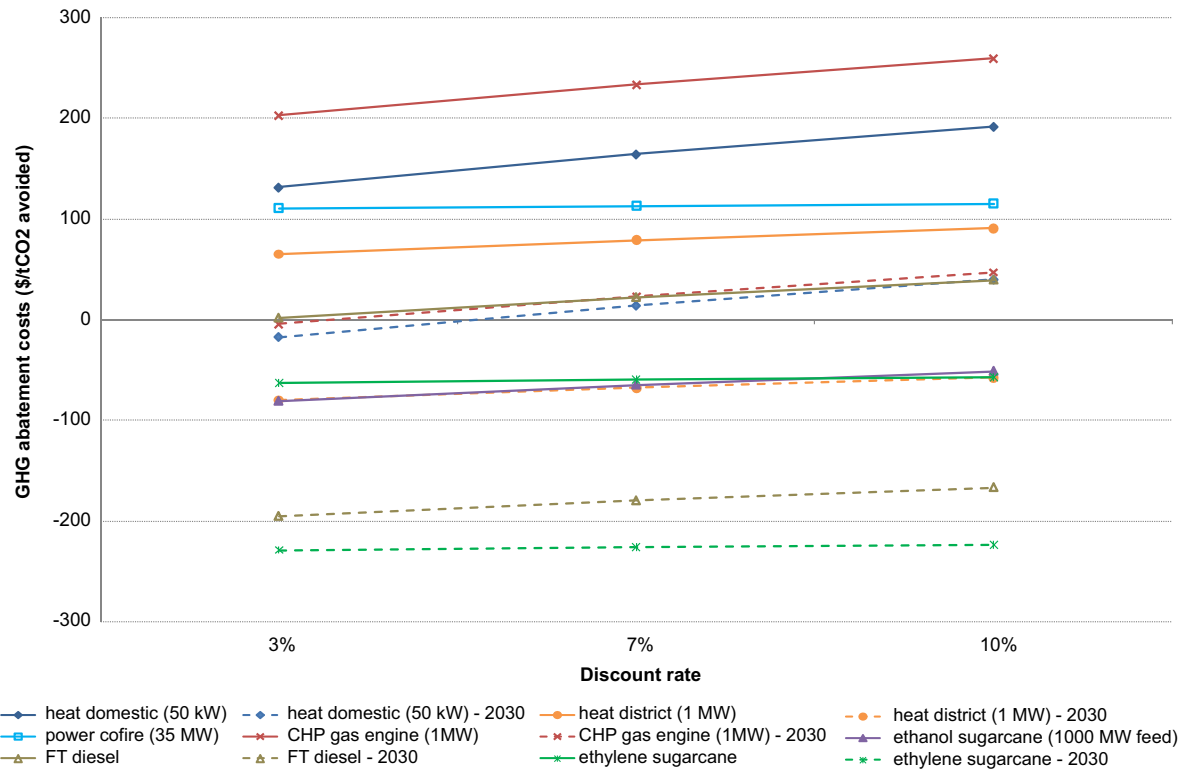
Fig. 12. GHG abatement costs as a function of the discount rate.
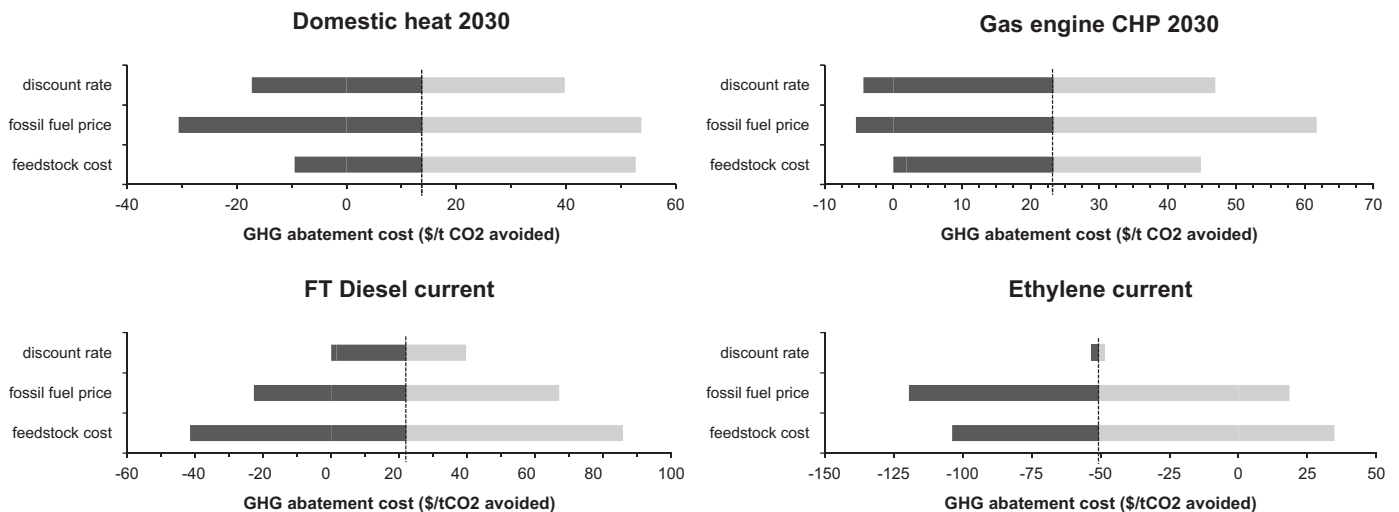

Fig. 13. Comparison of impact of feedstock cost, fossil fuel price and discount rate on the GHG abatement costs of (a) domestic heating 2030, (b) power generation by gas engine CHP 2030, (c) FT diesel current, (d) sugarcane ethylene current. Dotted line indicates abatement level at initial levels of discount rate, fossil fuel price and feedstock cost; lower discount rate, higher fossil fuel price and lower feedstock cost decrease the abatement costs (dark gray) and vice versa (light gray).

6. Discussion

This study is the first extensive review on the various uses of biomass and addresses the status and prospects as well as the economic and environmental performance of biomass value chains. Therefore, this study fills an important gap in the current literature. Still, our results are subject to uncertainties due to for example the quality of available data and to the assumptions made. We discuss the most important topics below.

6.1. Data availability and quality

The levelized production costs and GHG abatement costs were calculated based on cost and emission data from the literature. The availability and quality of this data, however, vary. With regard to data availability for bioenergy, the availability of GHG emission data was the factor that limited the amount of value chains for which GHG abatements costs could be calculated. In contrast, for biomaterials, the amount of GHG emission data was larger than

the amount of cost data. The lack of cost data for biomaterials limited the selection of value chains to fermentation- and gasification-based routes. In addition, less experience and empirical data is available for second-generation feedstocks than for established feedstock production and supply systems. Still, both costs and emissions of cultivation and logistics have been assessed in the literature. New pretreatment technologies like torrefaction, however, are not yet considered in LCA studies [23,156,169].

Concerning the data quality, the level of GHG emissions for agricultural crops, especially for corn and rapeseed, is very case-specific [23]. For conversion to second-generation biofuels, we found some variation in current (and to a lesser extent longer-term) cost estimates between various sources, which cannot be explained by scaling. Finally, the production costs of bio-based and fossil materials calculated in this work varied between sources and from cost estimates in the literature. This can mainly be explained by uncertainties in the underlying data. First, the economic assessment in the BREW project [15,93,150] was based on industry data, which are not publically available. To update this assessment, we applied triangulation or extrapolation based on publicly data provided for various crude oil prices. As the capital costs are not publically available, we needed to estimate the difference between the production costs and the product values. This estimation was based on publicly available data from other sources, which may be inconsistent with the BREW methodology. Also, it was not possible to adapt the capital costs for the long-term cost projections. Secondly, Ren et al. [14] state that the investment costs for the production of biomaterials are rather uncertain. However, they consider the effect of these uncertainties on the total production costs to be small in comparison with the effect of fluctuating feedstock and utility costs. Taking these considerations into account, we consider the data for biomaterials to be less robust than cost data for bioenergy. The production costs and GHG abatement costs found for biomaterials should be considered as an indication of their cost effectiveness.

6.2. Technological learning

The data used to calculate longer-term levelized production costs include assumptions on technological learning [54,142]. These assumptions are, however, not always explicitly defined in the literature. In Section 4.4.5, we discussed that the effects of technological learning are pathway dependent, and depend on both the specific system and on market volume development. For several established biomass value chains, experience curves have been derived in the literature. For novel feedstocks and conversion systems, which are still in the early phases of production, it is not possible to empirically determine progress ratios. However, the progress ratio is often a sensitive parameter for the determination of future cost levels [170]. Therefore, alternative approaches need to be used to assess cost developments of new systems and technologies.

In addition, in Section 4.4.5, we discussed that costs may decrease due to different learning mechanisms, triggered by factors such as R&D expenditures and technical improvements [3,171]. These different factors should be taken into account to make accurate estimates on learning rates and to assess future cost trends. However, the relationship between such factors and cost reductions is complex, and a better understanding of the reasons behind cost declines is still needed [[18,172,173]; [174] in:[175]]. Finally, other factors than technological learning may influence costs as well. For example, competition for land and/or biomass feedstocks can cause biomass feedstock prices to go up. Such mechanisms are not included in this study. The sensitivity analysis in Section 5.4 shows that higher feedstock prices may especially affect the levelized costs and GHG abatement costs of biofuels.

6.3. (I)LUC

Land use is an important factor in the production of biomass for energy and materials. Land use and changes in land use as a result of this production, however, can lead to unintended environmental, ecological and social impacts. One of the main issues discussed recently is the increase of GHG emissions induced by both direct and indirect land use change (DLUC and ILUC) [30]. We did not account for LUC related GHG emissions in our study. DLUC is location specific and depends on previous land use. Its impact can be negative (conversion of peat land forest) or positive (conversion of degraded land). ILUC-induced GHG emissions are market-mediated effects of bioenergy that cause LUC outside the feedstock production area. Various modeling exercises indicate that ILUC can have significant impacts on the total GHG emission balance [30]. Still, there are a lot of uncertainties and shortcomings in these models and there is a debate on how policy could deal with ILUC. Options include using feedstocks with low ILUC risks, such as agricultural and forestry residues and lignocellulosic energy crops (preferably produced on degraded and marginal lands), increasing efficiencies in agricultural crop and livestock production, and applying sustainable land use planning [30].

6.4. Allocation of costs and emissions

In our study, we applied system expansion to allocate costs and GHG emissions among the primary product and its by-products. The selected allocation method can, however, have significant impact on the results. Hoefnagels et al. [23] investigated the impact of the allocation method on the GHG balance of biofuels. They showed that the allocation method can influence the performance of a production chain. When allocated by mass, for example, the advantage is higher for systems that produce solid co-products than for systems that co-produce heat or electricity, which cannot be allocated on a mass basis. Also, system expansion benefits systems that produce a large amount of co-products, resulting in more by-product credits (see Section 4.5).

6.5. Fossil energy price in bioenergy costs

In the cost calculations for bioenergy, we assumed that all cost parameters are independent of the fossil energy price. However, this is a simplification as fossil energy consumption takes place in every biomass value chain (e.g. during transportation). As the fossil energy prices are hidden in, for example, transportation and O&M costs, it is beyond the scope of our work to take into account how these prices effect our calculations.

7. Conclusions

In this study, we reviewed the status and performance of biomass value chains for heat, power, fuels and materials. Using normalized and harmonized cost and GHG emission data, we calculated and compared current and projected (2030) levelized costs, avoided emissions and GHG abatement costs of different biomass value chains.

7.1. Levelized costs

Large-scale biomass-to-*heat* value chains can become cost competitive with fossil reference systems. At a wood pellet price of 9 $_{2009}$/GJ, the levelized costs of heat are 15 $/GJ$_{th}$ for a 100 kW domestic heating system and 18 $/GJ$_{th}$ for 5 MW district heating (8–20 $/GJ$_{th}$ for fossil reference systems at 75 $_{2009}$/bbl$_{oil}$). In 2030, these large-scale systems also become competitive with cheaper

fossil heating systems. At a pellet price of 4.5 $/GJ, the levelized costs are 9 $/GJ$_{th}$ for the 100 kW domestic heating system and 10 $/GJ$_{th}$ for 5 MW district heating (13–25 $/GJ$_{th}$ for fossil reference systems at 110 $_{2009}$/bbl$_{oil}$).

For biobased *power and CHP*, cofiring of wood chips and pellets is currently the most economically feasible option. The costs of direct cofiring of pellets (5–100 MW) are about 28–34 $/GJ$_e$ (fossil reference 7–20 $/GJ$_e$). Considering novel technologies, gasification-based biomass value chains, which apply large-scale IGCC and indirect cofiring technologies, have levelized costs of 25–40 $/GJ$_e$ for near-term commercial production and 11–26 $/GJ$_e$ in 2030 (fossil reference 13–37 $/GJe in 2030).

With regard to first-generation *biofuels*, large-scale (1000 MW$_{feed}$) production of Brazilian sugarcane ethanol (in an integrated sugar mill) attains the lowest costs (9–12 $/GJ$_{etOH}$ compared to 16 $/GJ$_{gasoline}$ (75 $/bbl)). Biodiesel production costs in the range of 18–49 $/GJ$_{biodiesel}$ and is nearly competitive in the cases of soy-based biodiesel and renewable diesel. Considering second-generation biofuels from lignocellulosic energy crops, short-term commercial production of thermochemical hydrogen (13–15 $/GJ$_{hydrogen}$) and methanol (about 12 $/GJ$_{methanol}$) may be cost competitive to gasoline and diesel. In the longer term, all value chains of second-generation biofuels are projected to become cost competitive and attain levelized production costs from 7–8 $/GJ$_{hydrogen}$ for hydrogen to 12–15 $/GJ$_{diesel}$ for FT diesel (22–24 $/GJ$_{fossil\ fuel}$ for fossil fuels at 110 $/bbl).

The production of *biomaterials* from low-cost Brazilian sugarcane (except butanol) is economically feasible. Currently, costs of ethylene, PLA, PHA and PTT are 270–865 $/t lower compared to their fossil reference products (sugar 141 $/t$_{ferm.sugar}$, oil 75 $_{2009}$/bbl$_{oil}$). In the longer term, this difference increases to about 940–1600 $/t (sugar 141 $/t$_{ferm.sugar}$, oil 110 $_{2009}$/bbl$_{oil}$). PLA has the best economic potential both today and in the longer term.

7.2. Avoided GHG emissions

The best option for domestic and district heating are wood chip and pellet boilers, both today (78–83 gCO$_2$-eq$_{avoided}$/MJ$_{th}$) and in 2030 (75–82 gCO$_2$-eq$_{avoided}$/MJ$_{th}$). Small-scale CHP technologies with low power–heat ratios receive a significant credit for heat and attain the highest GHG abatement levels for power generation. Gasification-based routes, which have higher power-heat ratios, attain abatement levels of 59–186 gCO$_2$-eq$_{avoided}$/MJ$_e$.

Sugarcane ethanol production is the best option amongst first-generation biofuels to abate GHG emissions (66–81 gCO$_2$-eq$_{avoided}$/MJ$_{etOH}$). Higher abatement levels can be attained by biomass value chains of second-generation bio-ethanol and FT diesel (72–91 gCO$_2$-eq$_{avoided}$/MJ$_{fuel}$), specifically from short rotation crops. Sugarcane ethanol and FT diesel are also preferred in the longer term because of increasing emission abatement (71–114 gCO$_2$-eq$_{avoided}$/MJ$_{fuel}$). For current biomaterials, sugarcane ethylene avoids most emissions (4.5–5.3 tCO$_2$-eq$_{avoided}$/t$_{ethylene}$). In the longer term, this is butanol from sugarcane (4.9–6.3 tCO$_2$-eq$_{avoided}$/t$_{butanol}$). Also FT olefins can attain high abatement levels (4.5–8.2 tCO$_2$-eq$_{avoided}$/t$_{olefins}$).

7.3. GHG abatement costs

Currently, the following biomass value chains have negative abatement costs (i.e. are cost effective and avoid GHG emissions): ethanol (sugarcane, large-scale production), ethylene (sugarcane and lignocellulosic feedstock), PLA (sugarcane and corn), and olefins (gasification of lignocellulosic feedstock). Heat and power production have positive abatement costs. For heat, district heating is currently the best option (75–79 $/tCO$_2$-eq$_{avoided}$ at a fossil reference cost of 12.4 $/GJ$_{th}$). For power generation, this is large-scale cofiring CHP (75–81 $/tCO$_2$-eq$_{avoided}$ at 100 MW$_e$ and a reference cost of 15 $/GJ$_e$) and

near-term commercial power production in a 250 MW IGCC-based CHP plant (71–115 $/tCO$_2$-eq$_{avoided}$). Based on limited longer-term projections, the biomass value chains of at least the following applications are expected to achieve negative abatement costs: district heat, (indirect) cofiring, IGCC, lignocellulosic biochemical ethanol and thermochemical FT diesel, and sugarcane butanol.

7.4. Overall

At present, the combined economic and environmental performance is best for the production of sugarcane-based ethanol, ethylene and PLA, followed by wood chip combustion in district heating systems and in cofiring power plants. In the longer term, fermentation of low-cost sugarcane remains attractive for the production of cost-competitive ethanol and materials with high GHG abatement potentials. In addition, advanced conversion technologies can play a key role in producing bio-based products that have both good economic and environmental performance. Biomass gasification can process various feedstocks and produce a wide range of products including heat, power, fuels and materials. Biochemical conversion of lignocellulosic biomass is promising for the production of both biofuels and biomaterials. Lignocellulosic energy crops can play a significant role in decreasing both the final production costs and life-cycle emissions of bioenergy (especially biofuels) and biomaterials. As the resource availability varies across regions, the importance of international trade and of (novel) pretreatment technologies will increase. Finally, the integration of different conversion technologies in biorefineries can maximize the use of all biomass components and improve the economic and environmental performance of the combined value chains.

Although the results show good perspectives for second-generation feedstocks and technologies and for biomaterials, there is still uncertainty about their actual performance. Projections are based on many assumptions, including technological progress and cost developments in biomass feedstock production, supply, and conversion. Technological and economical improvements are both preconditions for large-scale commercial implementation of biomass gasification and biochemical conversion of lignocellulosic biomass. The available data for production routes of biomaterials via fermentation and gasification give a good outlook for, for example, PLA and ethylene, especially in the longer term. Future research should pay extra attention to the economic performance of these and other biomaterials and on how and at what speed cost reductions can be achieved because data availability on this aspect is limited. As technological learning plays an important role in the reduction of costs, this should be an important topic in future research.

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Appendix A. Supporting information

Supplementary data associated with this article can be found in the online version at http://dx.doi.org/10.1016/j.rser.2014.07.197.

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